# Renewable Energy Implementation Toolkit: Development and Testing in South China


Center for Climate Strategies

Guangzhou Institute of Energy Conversion

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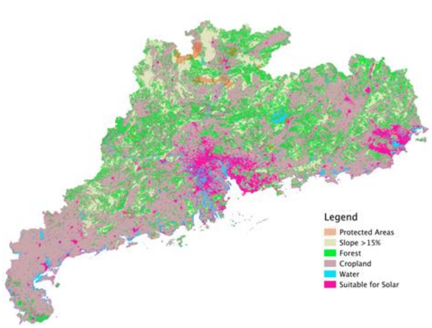


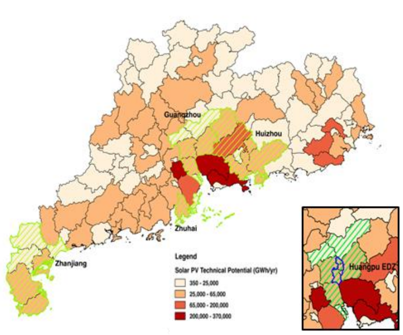


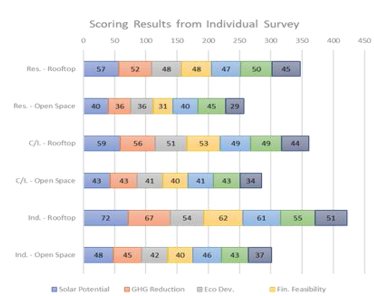

**DISCLAIMER**

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# Acronyms and Abbreviations

| | |
|---|---|
| BAU | Business as usual |
| CAS-IPM | Chinese Academy of Sciences – Institute of Policy and Management |
| CCS | Center for Climate Strategies |
| C/I | Commercial/institutional |
| DNCF | Discounted net cash flow |
| EDZ | Economic development zone |
| GEI | Global Environmental Institute |
| GHG | Greenhouse gas |
| GIEC | Guangzhou Institute of Energy Conversion, Chinese Academy of Sciences |
| GIS | Geographic information system |
| GoB | Government of Bangladesh |
| GSP | Gross state product |
| GW | Gigawatt |
| IDCOL | Infrastructure Development Company Limited (Bangladesh) |
| IRR | Internal rate of return |
| kW | Kilowatt |
| LCD | Low carbon development |
| LCOE | Levelized cost of electricity |
| LULC | Land use/landcover |
| $m^2$ | Square meters |
| MCA | Multi-criteria assessment |
| MW | Megawatt |
| MWh | Megawatt-hour |
| NDC | Nationally-declared contribution |
| NDRC | National Development and Reform Commission (China) |
| NPV | Net present value |
| NREL | National Renewable Energy Lab (United States Department of Energy) |
| O&M | Operations and maintenance |
| PO | Partner organization |
| PV | Photo-voltaic |
| RE | Renewable energy |
| REI | Renewable energy implementation |
| REZ | Renewable energy zone |
| ROI | Return on investment |
| SHS | Solar Home System (program of Bangladesh) |
| $tCO_2e$ | Tonnes of carbon dioxide equivalent |
| TID | Technology implementation document |

# Executive Summary

The Center for Climate Strategies (CCS), and its partners in China [the Guangzhou Institute of Energy Conversion - Chinese Academy of Science (GIEC) and the Global Environmental Institute (GEI)] have developed the Renewable Energy Implementation (REI) Toolkit. The REI Toolkit includes MS Excel-based workbooks, document templates, and guidance documents to assist jurisdictions (cities, provinces/states, and countries) in the evaluation, implementation and scale-up of renewable energy (RE) projects and programs. CCS considers "RE programs" to include a package of individual RE projects. This report summarizes the development of the REI Toolkit, including pilot application of tools for a 320 mega-watt (MW) industrial rooftop solar photovoltaic (PV) program in the Huangpu Economic Development Zone (EDZ) in Guangzhou, Guangdong Province, China.

The REI Toolkit represents an expansion of the subnational Low Carbon Development (LCD) Planning and Analysis System (LCD Toolkit) developed and instituted in China over the past five years by CCS, GEI, and the Chinese Academy of Sciences, Institute of Policy & Management (CAS-IPM). The LCD Toolkit was successfully piloted in a planning exercise for Chongqing and officially endorsed for subnational application throughout China by the National Development and Reform Commission (NDRC) in 2013. CCS and GEI subsequently provided capacity-building in LCD planning and toolkit application in 30 provinces and cities in China.

Successful RE implementation must address all of the details involved in planning, procurement, policy integration, financing, and installation of RE systems. This includes developing the business implementation models and information required to mobilize funding and other necessary capacities and authorities for RE implementation, and to integrate the activities of all responsible parties involved in a particular RE technology application at scale that is locally reliable and regionally scalable. The parties involved in implementation may include government planners, local stakeholders, impact investors, lenders, intermediaries, equipment and service providers, end users of RE technologies, technical service providers, and others.

Just as in broader-scale LCD planning, RE implementation follows a step-wise process. This process might begin following the development of a formal policy or plan for a jurisdiction that includes the establishment of goals for RE implementation. In such cases, the REI Toolkit can be linked to other sets of tools used to assist in planning for the development of renewable energy, such as tools for the development of energy plans, economic plans, or LCD plans. Alternatively, the REI Toolkit can be applied to address a specific and pre-determined need for local implementation and scale-up of RE “technology applications.” CCS has adopted the term "technology application" to cover a specific RE technology [e.g. solar photovoltaic (PV) panels, wind turbines); a targeted application sector (e.g. residential, commercial/institutional, industrial)]; and additional clarifying attributes (e.g. for solar PV systems, rooftop or open space installations). Proper definition of the technology application is needed to construct a viable implementation or "business" model.

The typical steps in RE implementation are as follows:

1. Jurisdictional-scale assessment of renewable energy zones (REZs) to determine the best opportunities for solar, wind, biomass and other RE resources to be found in the jurisdiction.
2. Selection of one or more RE resources (wind, solar, or biomass, for example) and target local implementation area(s) based on the REZ assessment and planning needs.
3. Characterization and selection of an RE technology application for the selected area. An “RE technology application” addresses both the “what” and the “where” aspects of renewable energy. This includes the end use sector (residential, commercial/institutional, or industrial) to

be targeted for the application, the technology (such as, solar PV panels), and additional application detail (for example, PV application on rooftops or in other open areas; use of tracking systems; and energy storage).

4. Development of a detailed RE Implementation model (or "business implementation model") and supporting documentation that includes:
    a. The detailed phases, steps, actions, agreements, parties, mechanisms, and information required to implement the program or project within the public and private sectors.
    b. Energy supply and demand assessment within the targeted local implementation area(s) to ensure high levels of local siting reliability and regional market penetration.
    c. Financial mapping of public and private resources for all phases, as well as detailed RE financial and implementation risk, return, and social impact analysis for the selected technology application and financing mechanism(s) selected to meet requirements of upstream, intermediary, and downstream parties to implementation.
    d. Linkages to relevant aspects of carbon trading, pricing, renewable energy credits, or other energy policies and programs, if present.
5. Activation of the implementation model, including formation of governance and intermediary structures, mobilization of funds, equipment purchases, technology installations and start-up.

The tools developed and applied in this project address aspects of each of the RE implementation steps mentioned above. Key components of the REI Toolkit are:

- Spatial Analysis Tool: an open-source geographic information system (GIS).
- RE Technology Multi-Criteria Assessment (MCA) Scoping Tool: assess and present results of both quantitative (empirical benchmarks) and qualitative (expert ratings) criteria to inform selection of high-priority RE technology applications.
- RE MCA Screening Survey Tool: gather and summarize expert input on selection of RE technology applications.
- LCD Toolkit Baseline Modules: assess local to provincial scale energy supply and demand.
- Business Implementation Model template to identify necessary mechanisms, procedures, and requirements of participants at the upstream, intermediary, and downstream levels
- Financial Risk and Return Assessment and Social Impact Analysis Tool: assess key financial and social impact metrics (e.g. discounted cash flows, return on investment, energy and environmental impacts).
- RE Technology Implementation Template: a comprehensive document that includes the technology implementation description, design, business implementation model, participant requirements, and the expected financial risk and return and social impacts of the project/program (energy, emissions, economic), as well as the approach to analysis and key elements such as data sources, methods, and key assumptions.

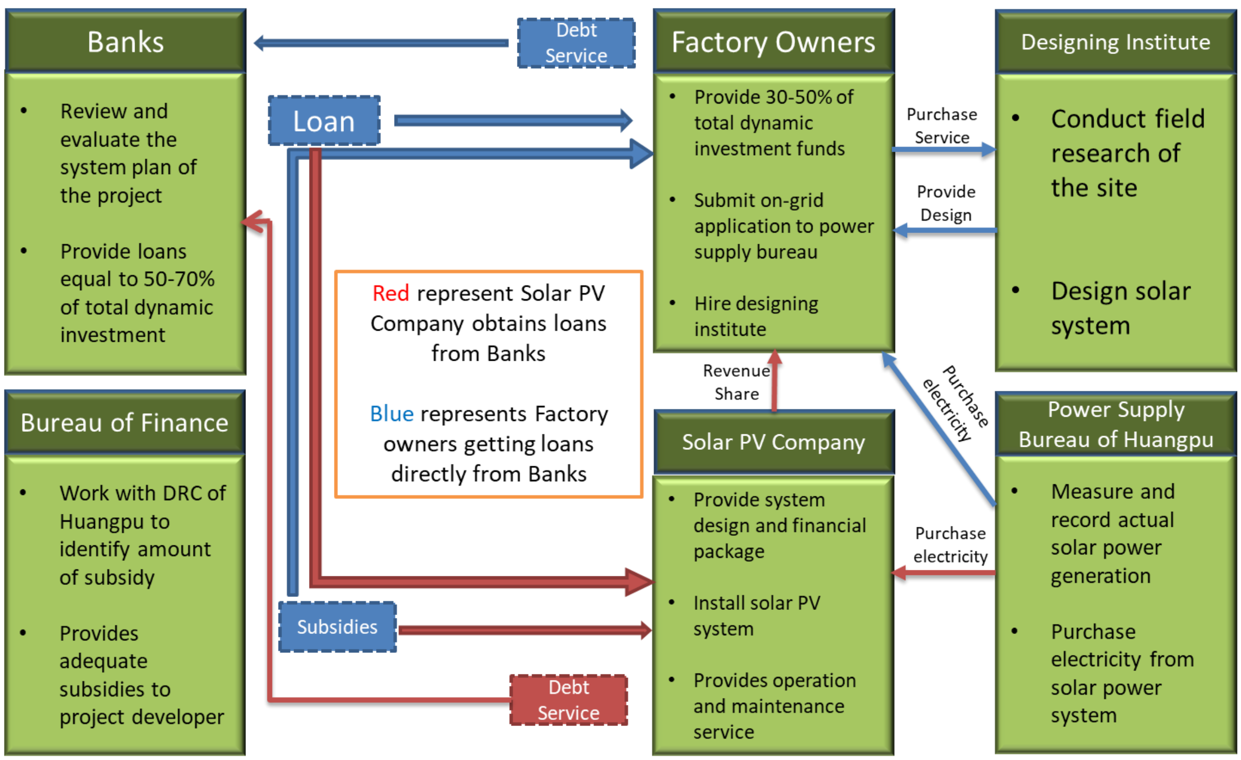
Additional publicly-available tools were also used in developing the REI Toolkit and are described in this report. The project team of GIEC, CCS and GEI carried out a pilot application of the REI Toolkit to address RE implementation needs for the Huangpu EDZ in Guangzhou (one of six EDZs in the province and 219 nationally in China). Provincial-scale solar REZ analysis and local-scale supply assessments indicated that rooftop solar PV systems had high potential for implementation in the Huangpu EDZ.

Subsequent application of the MCA Scoping Tool and a survey of 25 local experts using the MCA Screening Survey Tool indicated that the highest priority technology application should be solar PV systems applied to industrial rooftops. The total size of the program is 320 MW of capacity. Based on a nominal system size of 2.0 MW, the program will cover about 160 system installations. In Figure ES-1, the business (or program implementation) model is summarized including the key phases, individual steps, actions, parties, mechanisms, performance requirements, and procedures required for program level implementation.

Next steps for the project team will be to:

- Complete final analysis and begin implementation of the Huangpu Pilot.
- Assess and implement scale-up of the Huangpu Pilot to the provincial scale.
- Identify other forms of RE within Guangdong Province and South China region (starting with wind and biomass), extend tools to address these other resources, and identify target local areas for implementing projects or programs.
- Build capacity for LCD Planning and RE Implementation within other provinces or regions in similar "develop-design-learn-apply-implement" partnerships.

**Figure ES-1. Business Model for the Huangpu Industrial Rooftop Solar PV Program**. The Business Model features two different financing options. In financial model 1 (red), the solar PV company obtains loans from a bank and then provides all services directly to the factory owners (design, installation, follow-on O&M). All power is sold directly to the grid operator and a revenue sharing agreement is made between the factory owner and solar PV company. In financial model 2 (blue), factory owners obtain bank loans, and then contract separately for system design and system installation/O&M. The local power utility purchases excess power for the grid from the factory owner in financial model 1.



# Chapter 1. Introduction and Project Background

CCS, and its partners in China (GIEC and GEI) have developed a series of tools, including workbooks, document templates, and guidance documents, to assist jurisdictions (cities, provinces/states, and countries) in the implementation of comprehensive renewable energy (RE) systems. Collectively, these tools are referred to as the Renewable Energy Implementation (REI) Toolkit. The REI Toolkit was developed to bridge known gaps between energy/emissions/economic planning and the actual implementation of RE projects and programs at the local and regional scales. These gaps include:

- Knowledge gaps: such as highly reliable estimates of: RE resource potential in any given planning jurisdiction or targeted local area; the need for new RE power supply based on local demand requirements; the specific RE technology applications most suitable to a targeted local area.
- Financing and investment gaps: detailed financial mapping, analysis, and intermediary requirements of interested donors, investors, and lenders; available mechanisms and programs for financing RE projects/programs (including possible securitization of project packages to reach a larger investment community).
- Other implementation gaps: energy, environmental, and economic impacts assessment of projects/programs; linkages to cap and trade programs.

The REI Toolkit represents an expansion of the subnational Low Carbon Development (LCD) Planning and Analysis System (LCD Toolkit) developed and instituted in China over the past five years by CCS, GEI, and the Chinese Academy of Sciences, Institute of Policy & Management (CAS-IPM).[1] The LCD Toolkit was successfully piloted in a planning exercise for Chongqing and officially endorsed for subnational application throughout China by the National Development and Reform Commission (NDRC) in 2013. CCS and GEI provided capacity-building in LCD planning and toolkit application in 30 provinces and cities in China. The LCD Planning Process follows a step-wise process as shown in **Figure 1-1** below.

As part of Step 5 in the LCD process, details as to the specific implementation mechanisms required to implement an LCD policy are developed. A variety of instruments or mechanisms exist, including:

- *Voluntary agreements*
- *Technical assistance*
- *Targeted financial assistance*
- *Taxes, fees, or pricing*
- *Emissions trading*
- *Credits*
- *Codes and standards*
- *Disclosure and reporting*
- *Information and education*
- *Others*

[1] For example, see the following citation for background on jurisdictional scale planning for low carbon development (LCD) in China: Yu, Q., S.M. Roe, S. Xu, S. Williamson, N. Cui, J. Jin, T.D. Peterson, “China-U.S. cooperation on China's subnational low carbon planning toolkit development and application”, *Journal of Renewable and Sustainable Energy*, 7, 2015. http://scitation.aip.org/content/aip/journal/jrse/7/4/10.1063/1.4927000.

**Figure 1-1. LCD Planning Step-Wise Process**. Relative to RE implementation, the policy design conducted during Step 5 includes the identification of discrete implementation mechanisms needed to carry out each LCD policy.

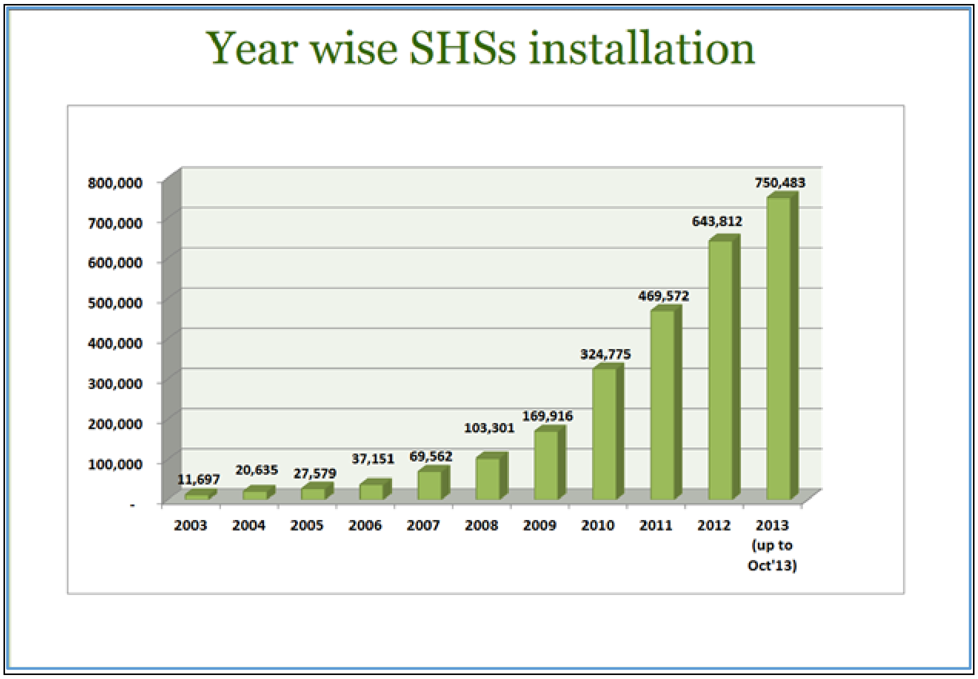
| | |
|---|---|
| Step 1 | Organization and Goals |
| Step 2 | Baseline Development |
| Step 3 | Policy Options Identification |
| Step 4 | Policy Screening & Prioritization |
| Step 5 | Initial Policy Option Design Specifications |
| Step 6 | Direct (Micro) Impacts Assessment |
| Step 7 | Policy Options Integration and Overlap |
| Step 8 | Indirect (Macro) Impacts Assessment |
| Step 9 | Final Recommendations & Report Transmittal |
| Step 10 | Monitoring, Reporting, Evaluation, & Updating |

To operationalize these mechanisms for implementation of RE policies, a very specific implementation or "business" plan needs to be developed to lay out the specific phases of implementation, their discrete steps, responsible parties for each step, and the agreements by each party. To implement any RE project/program, at least several responsible parties will be needed and typically include: local electrical utility; planning or other government agency; project developers; energy end user; and lending institutions. Among the key functions of the business plan is to lay out the expected financial flows required to implement the project/program.

CCS developed a series of sample "Technology Implementation Documents" (TIDs) built around business plans for real-world RE projects/programs, and these are provided as attachments to this report (see Attachment C - Attachment G). One of the most successful RE programs implemented in developing countries has been the Bangladesh Solar Home System (SHS) Program (see Figure 1-2 below).[2]

[2] Nazmul Haque, “IDCOL Solar Home System Program”, dated December 2013, and available as https://sustainabledevelopment.un.org/content/documents/4923haque.pdf.

**Figure 1-2. Ramp-Up of Solar PV Installations under the Bangladesh SHS Program**




A key reason for the success of the Bangladesh program was its financing scheme, as summarized in Figure 1-3 below.[3] The financing aspects make up most of the implementation steps the CCS reconstructed in the example TID shown in Attachment C:

**Step 1:** *Develop public policy and market penetration goals and matching financial mapping of public and private sources.*

**Step 2:** *Design and implement supporting governance and administrative mechanisms and gather information for program and market planning and evaluation.*

**Step 2:** *Multilateral agencies and other entities provide source funding for the program (e.g. grants and soft loans).*

**Step 3:** *Government of Bangladesh (GoB) receives the source funds and, together with the Bank of Bangladesh (BoB), sets up a special purpose entity (IDCOL) to administer and implement the program as an intermediary.*

**Step 4:** *Under supervision of the BoB, IDCOL and partners perform detailed program design and development, including putting in place administrative systems. This includes standardization of consumer transactions to enable aggregation and securitization.*

**Step 5:** *IDCOL Identifies franchisees, or Partner Organizations (POs), to administer financing mechanisms, marketing, customer acquisition, identify equipment suppliers, and provide management. IDCOL provide training and support and monitors the implementation of the program.*

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[3] Nazmul Haque, "DCOL Solar Home System Program", dated December 2013, and available as https://sustainabledevelopment.un.org/content/documents/4923haque.pdf.

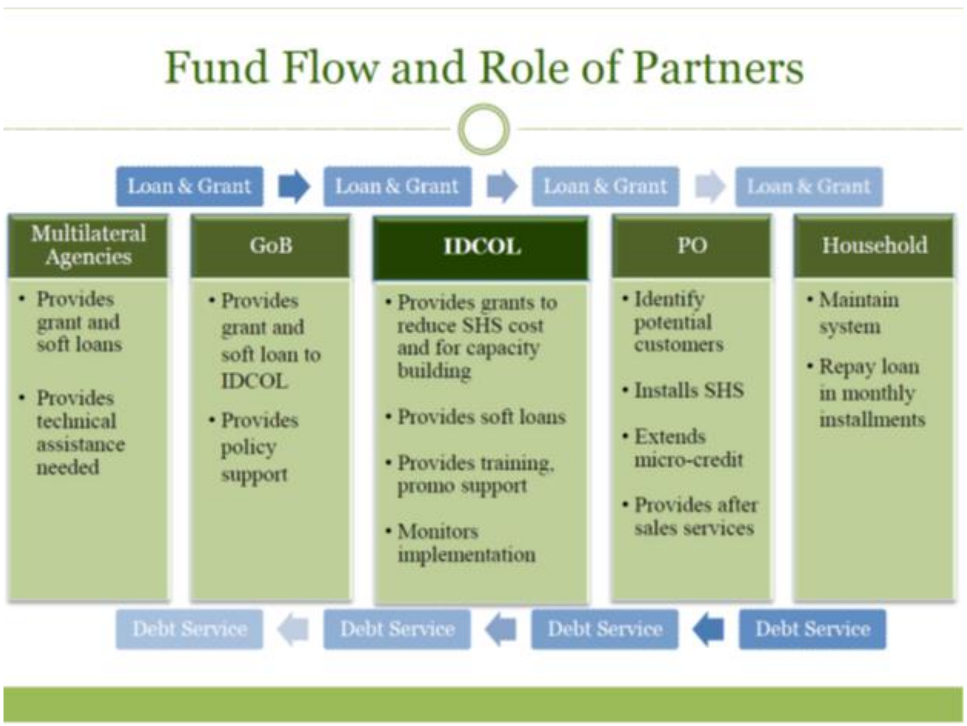
**Step 6:** *POs identify local customer territories (market segments), arrange for installation of solar home systems (SHSs) and provide after-sale services. PO also performs market analysis for prediction of the future trends in program adoption.*

**Step 7:** *Suppliers identified by POs install SHSs. POs, SHS suppliers or other companies provide phone support to customers and receive replace/repair technology guarantees. Program evaluation is carried out for POs and/or IDCOL by hired evaluation service providers.*

**Step 8:** *Households repay their loans in fixed monthly payments to POs. Households assume the ownership of the system.*

**Step 9:** *Based on Program Evaluation, program is scaled up to other jurisdictions in Bangladesh, and potentially to other customer segments.*

**Figure 1-3. Financial Mapping for the Bangladesh SHS Program**




Based on the review of the example TIDs, the project partners developed an approach to assessing RE implementation opportunities in Guangdong province, as well as a set of tools needed to conduct those assessments. Those tools are collectively referred to as the Renewable Energy Implementation (REI) Toolkit. A description of the REI Toolkit and its pilot application in Guangdong Province is provided in the rest of this report.

# Chapter 2. Overview of Renewable Energy Implementation and the REI Toolkit

As with LCD Planning introduced in Chapter 1, RE implementation should also follow a step-wise process. This process might begin following the development of a formal policy or plan for a jurisdiction that includes the establishment of goals for RE implementation. Hence, the REI Toolkit can be linked to other sets of tools used to assist in planning for the development of renewable energy, such as tools for the development of energy plans, economic plans, or low carbon development plans.[4] Alternatively, the REI Toolkit can be applied to address a pre-determined need for "technology application" (such as the development of residential solar photovoltaic (PV) programs).

RE implementation involves developing and preparing the additional details involved in planning for, procuring, financing, and installing RE systems, including developing the information required to mobilize funding for RE implementation, and to integrate the activities of all responsible parties involved in a particular RE technology application at scale. The parties involved in implementation may include lenders, equipment providers, end users of RE technologies, technical service providers, government agencies, and others. The typical steps in RE implementation are as follows:

1. Jurisdictional-scale assessment of renewable energy zones (REZs) to determine the best opportunities for solar, wind, biomass and other RE resources to be found in the jurisdiction.
2. Selection of one or more RE resources (wind, solar, or biomass, for example) and target local implementation area(s) based on the REZ assessment and planning needs.
3. Characterization and selection of an RE technology application for the selected area. An "RE technology application" addresses both the "what" and the "where" aspects of renewable energy. This includes the end use sector (residential, commercial/institutional, or industrial) to be targeted for the application, the technology (such as, solar PV panels), and additional application detail (for example, PV application on rooftops or in other open areas; use of tracking systems; and energy storage).
4. Development of a detailed RE Implementation model (or "business implementation model") and supporting documentation that includes:
    a. The detailed phases, steps, actions, agreements, parties, mechanisms, and information required to implement the program or project within the public and private sectors.
    b. Energy supply and demand assessment within the targeted local implementation area(s) to ensure high levels of local siting reliability and regional market penetration.
    c. Financial mapping of public and private resources for all phases, as well as detailed RE financial and implementation risk, return, and social impact analysis for the selected technology application and financing mechanism(s) selected to meet requirements of upstream, intermediary, and downstream parties to implementation.

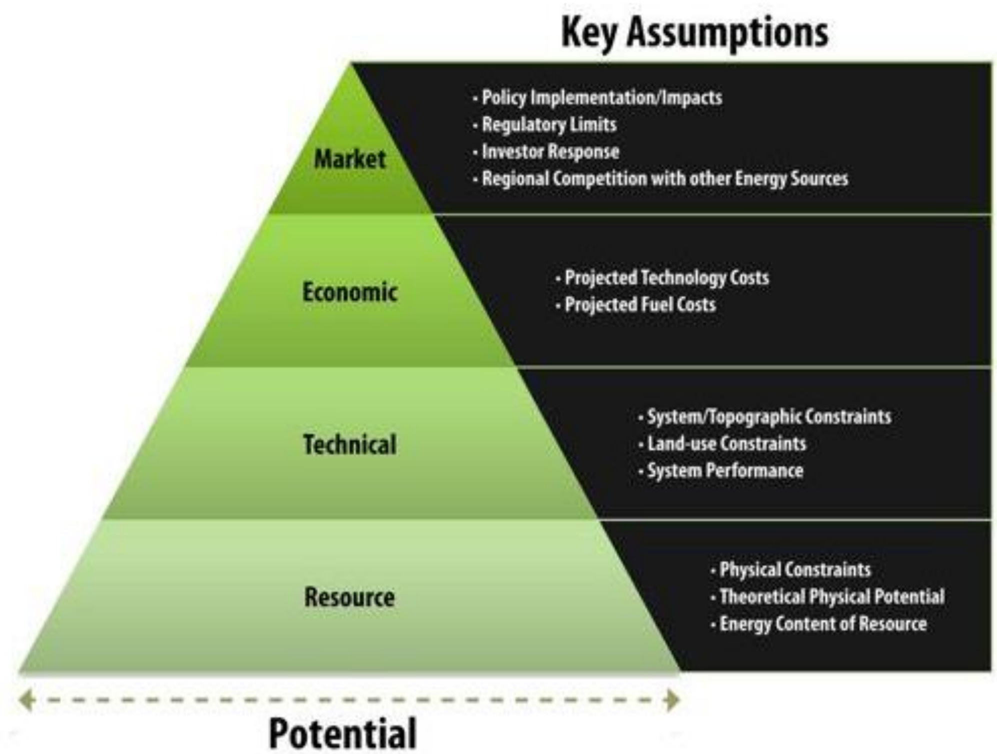
[4] For example, see the following citation for background on jurisdictional scale planning for low carbon development (LCD) in China: Yu, Q., S.M. Roe, S. Xu, S. Williamson, N. Cui, J. Jin, T.D. Peterson, "China-U.S. cooperation on China's subnational low carbon planning toolkit development and application", *Journal of Renewable and Sustainable Energy*, 7, 2015. http://scitation.aip.org/content/aip/journal/jrse/7/4/10.1063/1.4927000.

   d. Linkages to relevant aspects of carbon trading, pricing, renewable energy credits, or other energy policies and programs, if present.

5. Activation of the implementation model, including formation of governance and intermediary structures, mobilization of funds, equipment purchases, technology installations and start-up.

The location(s) for RE implementation are selected based on geospatial analysis of available renewable resources. Areas with significant RE potential are often referred to as renewable energy zones or REZs. Pioneering work in this area has been done by the US Department of Energy's National Renewable Energy Lab (NREL).[5] In identifying and characterizing REZs, the first two levels of the RE potential pyramid in Figure 2-1 below are involved. First, estimates of the total "Resource" are determined. Using distributed solar PV in Guangdong Province as an example, this involves determining the total area theoretically available for applications (e.g. area of each city or district) and the average annual solar insolation (e.g. watt-hr/day) in the area, which are multiplied to yield total "Resource" estimates of gigawatt-hrs./day.

**Figure 2-1. Identifying RE Opportunity Potential[6]**




Source: NREL

[5] See for example: http://greeningthegrid.org/resources/factsheets/renewable-energy-zones.
[6] Source: NREL presentation, "Implementing Renewable Energy Zones for Integrated Transmission and Generation Planning", Enhancing Capacity for Low Emissions Development Strategies (EC-LEDS). http://greeningthegrid.org/trainings-1/presentation-implementing-renewable-energy-zones-for-integrated-transmission-and-generation-planning.

The "Technical" potential is determined next by identifying and excluding areas that are not amenable to RE installation due to location. Areas can be excluded due to land use constraints, including incompatibilities with existing land uses (such as for agricultural crops) and protected areas. System performance is also factored in at this stage. In the example of Guangdong Province distributed solar PV, consideration of system performance involves applying the expected conversion efficiency from solar insolation to output power by the PV systems.[7] Depending on the technology used, a different conversion efficiency would be applied for concentrated solar power plants or distributed solar hot water heating systems.

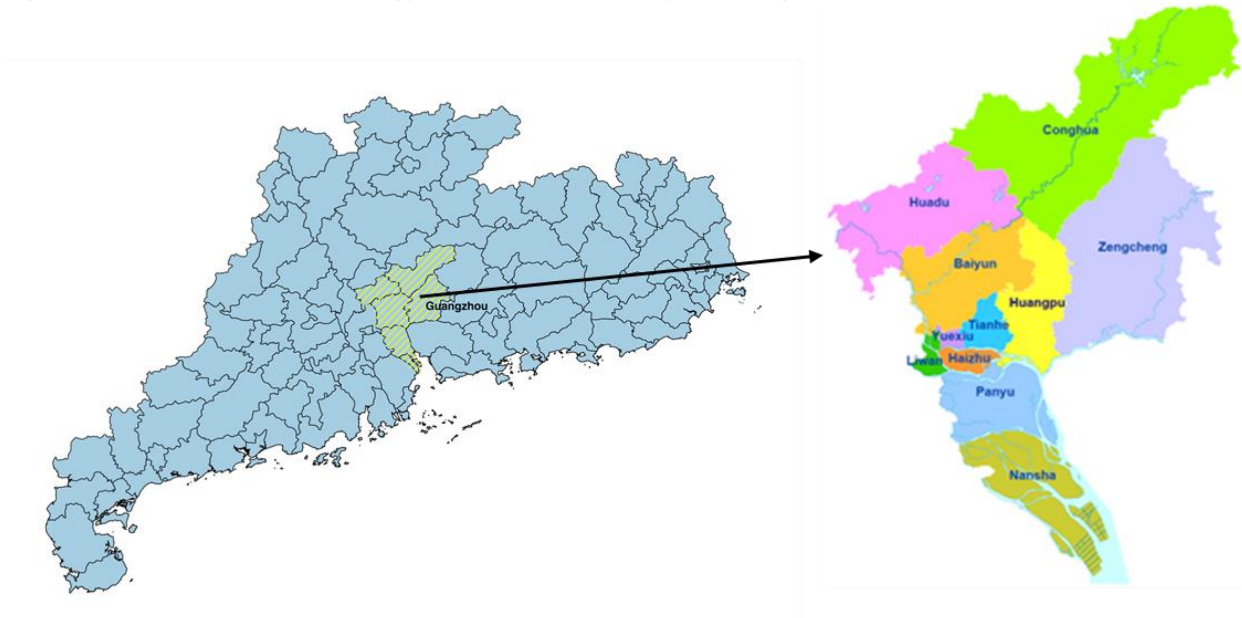
The rest of this paper focuses on how the REI Toolkit can continue to be applied to move further up the "Resource Pyramid" shown in Figure 2-1 above and to develop a set of detailed instructions, responsibilities, and agreements for implementing the RE program/project. For distributed solar PV, determining "Economic" potential requires additional local area assessment of the physical structures or open areas where solar PV can be applied, as well as at least a screening-level assessment of installation and operational costs.[8] Finally, "Market" potential can be determined by examining the factors listed in Figure 2-1, as well as more detailed cost estimates and financing assumptions. Importantly, these factors include expected investor response.

Once the REZs have been identified, these zones could serve as the local areas for assessment of economic and market potential.  There may, however, be other considerations applied to narrow the number of zones or to further delineate the local geographic coverage of the RE program/project of interest. In the case of solar PV in Guangdong Province, project participants were interested in prioritizing implementation in local economic development zones, or "EDZs" (there are six of these in Guangdong Province). As a consequence, the local areas for RE system implementation were selected based on where the REZs (areas of highest technical potential) coincided with EDZs (see Chapter 3). Among these, the Guangzhou Economic and Technological Development Zone located in the Huangpu District (Huangpu EDZ) within the city of Guangzhou was the first local area selected for development of an implementation model (see **Figure 2-2**; Huangpu is located at the geographic center of Guangzhou). Another reason for its prioritization among the other EDZs with good solar potential is that the northern portion of Huangpu is currently being developed and near-term opportunities are therefore available to integrate RE into ongoing and upcoming construction.

Following the selection of the local area, the next step involves further delineation of the specific technology application. Hence, for distributed solar PV, this includes the end use sector for installation (residential, commercial/institutional, industrial), as well as whether the installations will be rooftop or over some available open space (e.g. parking lots, public squares, other paved areas, etc.). This assessment of available rooftop and other open area by sector is also done using the GIS tool within the REI toolkit. In addition to available areas for installation within the implementation area, information should also be gathered at this stage on cost and performance characteristics of differing options for the RE technology application.

[7] See the previous CCS White Paper referenced above for more details on assessing technical potential.
[8] A useful metric for direct costs at this stage is the levelized cost of electricity (LCOE) which captures installation costs, operational costs and expected performance of different RE systems. LCOE estimates can then be directly compared across RE technologies.

**Figure 2-2. Location of the Huangpu EDZ within the City of Guangzhou**




Since at least several different options for technology applications will be possible for each RE resource, further specification or prioritization of these options can be done using multi-criteria assessment (MCA). MCA is used to screen among a candidate list of applications to identify those that score the highest with respect to important performance criteria that match overall public policy and market goals. Theses may include production potential, production costs, or other applicable criteria that can be considered. For example, if solar energy was determined to be the best RE resource in an area, then MCA can be used to select among different application choices, for example, among sectors (residential, commercial/institutional, industrial), applications (rooftop, other open area), and technology details (such as distributed PV panels, PV farms, concentrated solar power, and/or solar hot water). MCA also provides critical guidance for subsequent program and product design to meet combined performance objectives.

Input from a local expert review group is highly valuable in making appropriate choices for RE implementation. Based on informed comparison of alternatives, screening surveys and or facilitated work group sessions can identify directions and implementation details that lead to better choices for the highest priority technology applications identified in previous steps. Using distributed solar PV applied to industrial rooftops as an example application, an expert group could inform planners whether inclusion of battery storage, single- or dual-axis tracking, or specific PV chemistries should be favored based on current technologies and market conditions.

Financial and implementation risk analyses are key requirements for RE implementation and for a determination of market potential. Among other risks, such analyses help lenders to understand the expected financial performance of the RE program or project being considered for implementation, and to identify the magnitude of potential risks from the borrower with respect to loan repayment.

The business implementation model details each step of implementation, including each of the responsible parties and their responsibilities, the agreements needed, mechanisms, and analytical requirements of financial supporters. Details on the contents of a business implementation model are provided later in this paper. The Implementation Model is documented within the framework of a document template.

Table 2-1 lists the tools developed and piloted by CCS and its partners, as well as some additional tools developed by other organizations, that could be applied in each step of the RE implementation process depending on project needs. Also listed is the function of each tool or software application. More detailed methodologies for each step are provided in later chapters of this report.

**Table 2-1. Key RE Implementation Tools**

| Implementation Step | Tool | Function |
|---|---|---|
| 1. Jurisdictional-scale assessment of REZs;<br>2. Select RE resource and location | Spatial Analysis Tool (e.g. QGIS[9]) | Characterize jurisdictional scale RE resource categories (wind, solar, biomass, hydro) |
| 3. Selection of RE technology application | Spatial Analysis Tool (e.g. QGIS) | Local scale RE technology application potential (e.g. rooftop solar PV, ground-mounted solar, micro-hydro, biomass feedstocks, on or offshore wind) |
| | RETScreen[10] | Clean energy management software from Natural Resources Canada. Among its uses, exploration of RE technology performance and cost parameters (including as input to other tools noted below). |
| | RE Technology Multi-Criteria Assessment (MCA) Scoping Tool | Assessment of optimal RE technologies for each resource category at the local level based on both empirical analysis and expert ratings of:<br>• Available local potential<br>• Expected performance<br>• Expected cost<br>• Alignment with jurisdictional/national objectives on clean technology, energy security, GHG emissions, etc. |
| | RE MCA Screening Survey Tool | Used to engage a local group of RE experts who provide input on technology application choice and prioritization for local implementation. |
| 4. Energy supply and demand assessment | Low Carbon Development (LCD) Toolkit Baseline Modules | Energy and GHG Baseline Workbooks –<br>• Energy Supply<br>• Energy Demand:<br>• Residential, Commercial, Institutional<br>• Industrial<br>• Transportation |
| | LEAP[11] | Dynamic Energy Accounting and Scenario Development/Analysis Model developed by the Stockholm Environmental Institute - US |

[9] QGIS Website: http://www.qgis.org/en/site/.
[10] RETScreen website: http://www.nrcan.gc.ca/energy/software-tools/7465.
[11] LEAP Website: http://sei-us.org/software/leap.

| Implementation Step | Tool | Function |
|---|---|---|
| 5. RE financial and social impact analysis | Financial and Social Impact Tool | Conducting risk adjusted net present value (NPV) assessments of selected RE technologies for multiple objectives:<br>• NPV of program/project costs and benefits/savings, including financial and social impact criteria<br>• Financial return metrics, including Discounted Cash Flow (DCF) based analyses of NPV, Internal Rate of Return, Payback Period, etc.<br>• Risk evaluations for key areas, such as technology, market, costs, and governance.<br>• Risk-Adjusted Financial and Social Metrics |
| 6. RE business implementation model and documentation | RE Technology Implementation Template | Documents the following:<br>• Description of Selected RE Technology<br>• Business Implementation Model (stepwise implementation elements, agreements, actions, and requirements for each responsible party)<br>• Baseline Conditions: current and business as usual (BAU) energy supply and demand conditions at the jurisdictional and local levels<br>- Expected Impacts: RE energy production (localized and scaled-up to jurisdictional scale); GHG emissions impacts; program/project level costs; financial risk |

# Chapter 3. Assessment of Renewable Energy Zones

Geospatial analysis, using Geographic Information System (GIS) software such as QGIS, is used to assess both the total jurisdictional resource potential for a particular RE resource (solar, wind, biomass, hydro) and the areas within the jurisdiction with the greatest potential for implementation. Once a general location of high potential is identified (an REZ), more specific local assessment can be conducted, as described under the section for Selection of RE Technology Application below.

REZ analysis is based on identification and quantification of the specific land areas where the RE resource is available. These area assessments are based on data such as land use/land cover (LULC) and slope data. The amenable land area estimates are then combined with other data, such as solar insolation, wind resource, or biomass production and energy conversion efficiencies to estimate the resource potential of differing local areas. Areas considered rich in technical potential can be considered REZs, if appropriate transmission/transport systems are available (or are included as part of the technology application itself) to get the energy produced to its end use market.

The types of local map data useful for this REZ analysis include:

- Land Use/Land Cover: to identify areas that are suitable or unsuitable for RE system installation. For example, forested areas would be unsuitable for solar PV.
- Protected and Sensitive Areas: to identify natural areas that where RE systems cannot be installed due to restrictions on development.
- Digital Elevation Models (DEM): provides data on elevation, slope, and aspect that would help identify areas that are suitable or unsuitable for RE system installation. High slope areas would be unsuitable for solar installations, but are preferred for micro-hydro systems.
- Population Density: helps determine suitable areas for installation, depending on whether system should be sited away from settlements or should be near end-use demand (and/or integrated with building or other infrastructure).
- Agricultural Production: identifies location of crop types and production from which biomass feedstock availability can be estimated; also identifies locations of rice mills and other possible sources of collected feedstocks.
- Infrastructure: aids in selection of suitable locations based on proximity to infrastructure such as roads, electrical transmission equipment (existing and planned; including the location of substations), railroads, or port facilities (for example, for shipping of biomass or wind power system components).
- Solar Insolation: amount of solar energy reaching the Earth's surface, varies by latitude and local atmospheric conditions.
- Wind Speed: varies by location; for coastal regions both offshore and onshore wind data are typically needed.
- Stream Levels and Streamflow: useful in selection of suitable locations for hydro-power (particularly micro-hydro plants).

Following the assessment of resource potential across the RE resource categories (wind, solar, biomass, hydro), the next step involves selecting one of those resources for further analysis and the ultimate development of an implementation model for a selected RE technology application. This selection could be made based on overall resource or technical potential, but, other factors might also be considered, including availability of government incentives or alignment with provincial or national goals. For this paper, solar energy is the RE resource used for illustrating the full development of an implementation model, as described in the sections that follow.

The case used in this report is the solar RE resource assessment for Guangdong Province which was assessed based on the maximum area available for solar installation and the amount of solar energy reaching the ground (solar insolation). This assessment was conducted using geo-spatial analysis within a Geographic Information System (GIS) to calculate the maximum area available. The area within the province that is suitable for installation of solar PV systems was estimated by subtracting unsuitable areas from the total provincial area, including forest, cropland, water, protected and sensitive areas, land with slope greater than 15%.

For this study, forests were considered incompatible with solar installations due to shading and, as with protected and sensitive areas, the desire to limit land use conversion in these areas. Water was also excluded from the area suitable for solar development. Although floating solar systems have been developed, these are intended for artificial water bodies such as holding ponds, and should not be used on natural water bodies.

Cropland is also typically excluded from solar resource assessments, since the shade cast by solar installations would likely negatively affect yields on most croplands. Therefore, these areas were excluded for this assessment. There could be some opportunity for solar development on agricultural land, such as: on grazing land for small livestock; among some crops that can be grown in partial shade conditions; through conversion of marginal agricultural land; and in small areas between fields. These opportunities were assumed to be limited. In addition, more refined spatial data for croplands would be needed, which were not available for this study (e.g. breakdown of cropland to pasture, field crops, row crops, marginal cropland, etc.).

For highly sloped lands, topographic features can create strong local gradients in insolation received at the surface. A solar resource assessment for the EU found that slope of 16% and greater was poorly suitable for solar energy, with greater than 30% being technically unviable.[12] The area resulting from the 15% slope limit should considered an upper bound of the area suitable for solar, as other studies have used lower slope limits of 5% or lower for determining the locations most desirable for solar development.[13]

The remaining area, after removal of unsuitable areas, was calculated for each of the smallest available administrative divisions for Guangdong province, referred to here as township. The remaining area for each township was then multiplied by the annual solar insolation for that location to estimate the available solar energy resource. This approach is similar to the methods to identify REZs.

**Figure 3-1** provides a map of Guangdong province showing the areas suitable for solar energy applications.[14] These areas (bright pink) are concentrated along the coastal portions of the province, in particular in the Pearl River delta area near the center of the coast.

[12] Castillo, et al., 2016. An assessment of the regional potential for solar power generation in the EU-28. Energy Policy. https://doi.org/10.1016/j.enpol.2015.10.004.

[13] Simons and McCabe, 2005. California Solar Resources. http://www.energy.ca.gov/2005publications/CEC-500-2005-072/CEC-500-2005-072-D.PDF.

[14] See the CCS White Paper referenced above for details on this assessment. This is an example of estimating an upper limit on the amount of area available for installation of solar systems by removing all area deemed unsuitable, such as forested land, crop land, water, protected areas, and land with slope greater than 15%.

Figure **3-2** provides the technical potential for solar energy (assuming application of distributed PV generation) at the township level based on the available areas shown in **Figure 3-1**. Other possible considerations for this type of analysis include land (or offshore) areas within a specified distance of specific types of infrastructure, such as electrical transmission lines (especially for concentrated solar power installations), roads, and population centers. This type of analysis can be conducted on multiple types of RE resources (for example, solar, wind, biomass, micro-hydro) to determine what resource options provide the most generation potential and the optimal locations for siting RE systems.

The local area(s) for implementation should be based on the technical potential assessment and other selection criteria important to development within the region. Local areas could be the entire REZ or portions of an REZ that fall within jurisdictional boundaries (counties, cities, townships, districts). Local areas rich in resource potential might be further prioritized based on expected demand growth for power, targets for economic growth, or other criteria. For our example in Guangdong Province, the Chinese government has established Economic Development Zones (EDZs). There are six EDZs in Guangdong province, as shown in

Figure **3-2**. Of these, the Huangpu EDZ showed good technical potential for solar power. In addition, the northern portion of Huangpu is currently being developed as the Sino-Singapore Knowledge City which offers near term opportunities to integrate solar power into the construction of new industrial buildings. Hence, it was selected as the first local area for development of an RE implementation model for solar energy.

**Figure 3-1. Guangdong Province Land Cover and Area Suitable for Solar Installation**. These areas (bright pink) are concentrated along the coastal portions of the province, in particular in the Pearl River delta near the center of the coast.

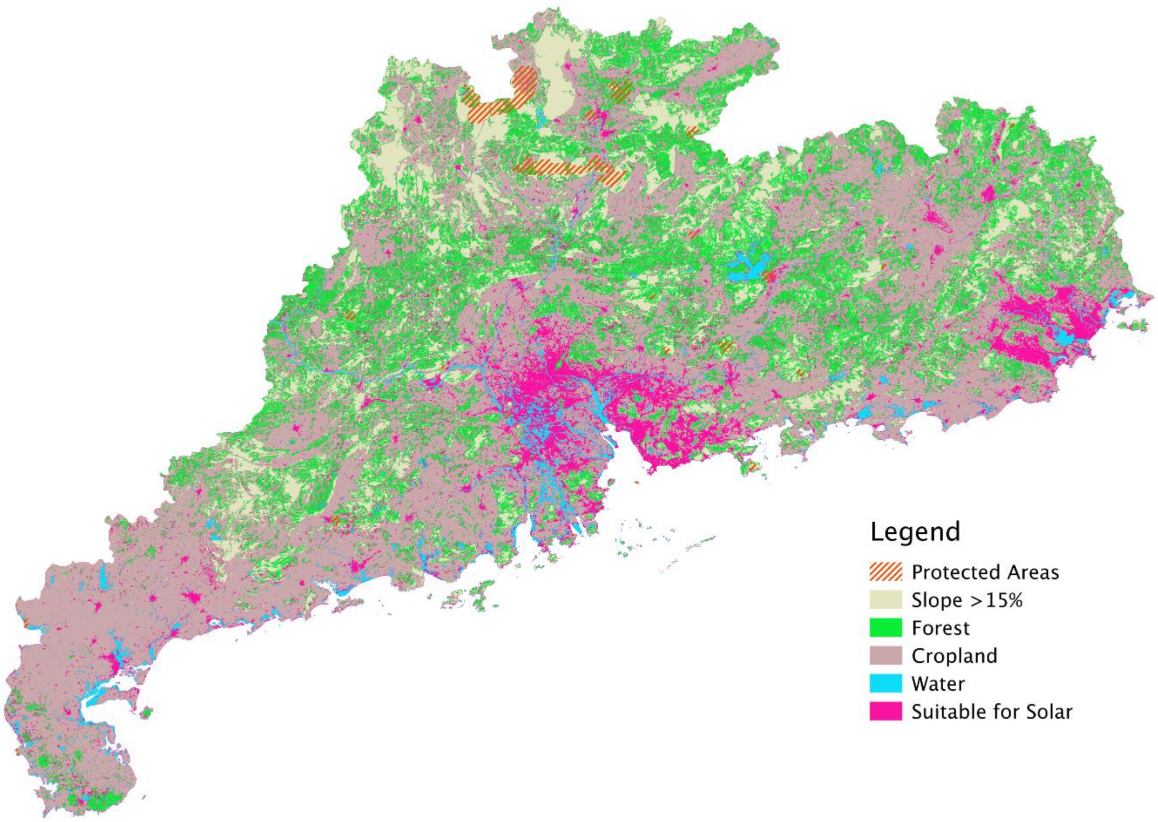


**Figure 3-2. Guangdong Province Solar PV Technical Potential and Location of EDZs**. In addition to Zhanjiang, Zhuhai and Huizhou, there are three additional EDZs located within the City of Guangzhou. The location of the Huangpu EDZ within the City of Guangzhou is shown in the inset map.

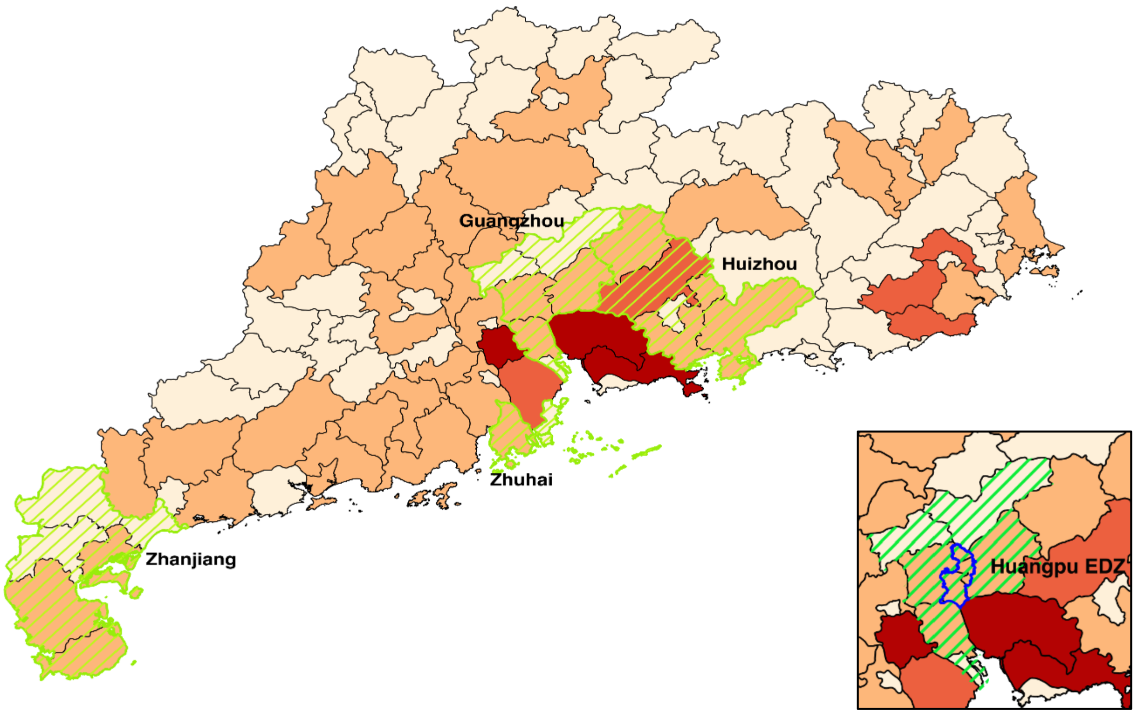



**Table 3-1. Guangdong Solar Area and Technical PV Potential**

| City (EDZs) | Area Suitable for Solar (m²) | Potential PV Capacity (GW) | Technical Power Generation Potential (GWh/year) |
|---|---|---|---|
| Chaozhou | 290,239,384 | 51 | 62,390 |
| Dongguan | 851,363,293 | 146 | 172,748 |
| Foshan | 1,502,248,620 | 251 | 287,114 |
| Guangzhou (Huangpu, Nansha, and Zengcheng EDZs) | 810,277,475 | 133 | 152,039 |
| Heyuan | 348,808,914 | 58 | 66,962 |
| Huizhou (Daya Bay EDZ) | 855,827,584 | 147 | 171,466 |
| Jiangmen | 857,388,799 | 141 | 159,884 |
| Jieyang | 1,656,794,952 | 293 | 354,423 |
| Maoming | 661,424,536 | 111 | 126,790 |
| Meizhou | 595,444,399 | 101 | 117,588 |
| Qingyuan | 709,819,477 | 110 | 118,015 |
| Shantou | 469,767,446 | 86 | 107,523 |
| Shanwei | 309,780,909 | 54 | 65,404 |
| Shaoguan | 388,781,994 | 60 | 64,299 |
| Shenzhen | 1,543,208,328 | 270 | 321,812 |

| City (EDZs) | Area Suitable for Solar ($m^2$) | Potential PV Capacity (GW) | Technical Power Generation Potential (GWh/year) |
|---|---|---|---|
| Yangjiang | 565,620,315 | 95 | 107,643 |
| Yunfu | 291,814,403 | 47 | 51,067 |
| Zhanjiang (EDZ) | 783,972,721 | 136 | 160,551 |
| Zhaoqing | 972,434,407 | 154 | 166,204 |
| Zhongshan | 527,741,190 | 89 | 104,242 |
| Zhuhai (EDZ) | 234,843,746 | 40 | 47,364 |
| **Total** | **15,227,602,892** | **2,572** | **2,985,526** |

# Chapter 4. RE Resource Assessment at the Local Scale

After determining the highest priority RE resource and local area(s) for implementation, the next step involves building additional detail on the technology application to be implemented. For solar RE, additional details that are needed here include: economic sector involved (residential, commercial/institutional, or industrial); technology detail (for example, distributed PV systems, concentrated PV systems, solar water heating, concentrated solar plants); and application detail (such as rooftop or installation above other open area).

Among the solar technology options, the local partners in Guangdong province selected distributed PV systems based on consideration of a combination of spatial limitations in the Huangpu EDZ that argued against application of other technologies (such as concentrated solar) and on the existing penetration of some technologies (for example, solar water heating being already much more common that solar electricity).

After choosing a specific local area for RE implementation, geospatial analysis can also be used to conduct a local resource assessment to obtain more detailed information valuable for selecting the RE technology application. For the solar PV example, a local assessment can be conducted to determine the area of rooftops and open space in the residential, commercial/ institutional, and industrial sectors available for solar PV installation.

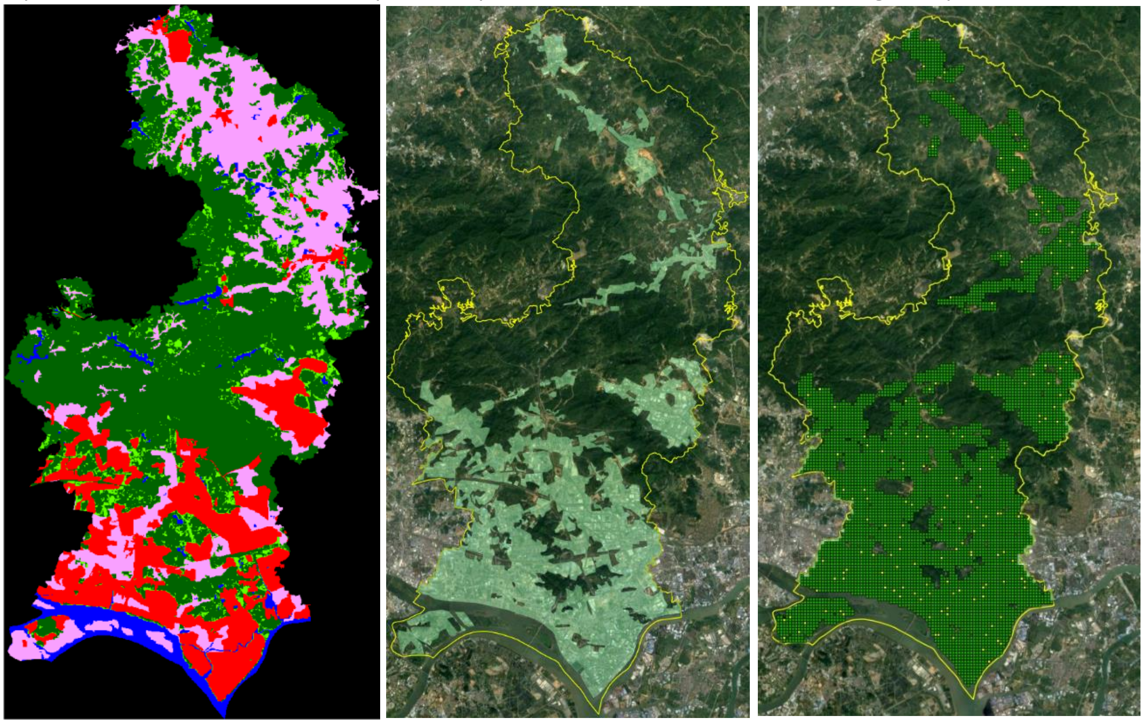
To estimate the amount of rooftop and urban open space area available for solar PV installation, the urban area can be selected based on land cover data, similar to the process used in the jurisdictional assessment described above. If necessary to improve the accuracy of the land cover data, the urban area selection can then be compared to a satellite image of the area and manually corrected. The urban land selection is then divided into a grid, as shown in the last panel in **Error! Not a valid bookmark self-reference.** showing grid squares overlaid on the urban area in Huangpu District, Guangzhou. Most grid squares are shown in green; a random sampling of these grid squares is shown in yellow.

Ideally, the urban land selection should be further sub-divided into Residential, Commercial/ Institutional, and Industrial zones (sector zones) based on local zoning or planning data. If the zoning data are not available, visual inspection of the satellite images for the area can provide a means to manually create a rough division of sector zones. Then, each sector zone would be separately random-sampled as described below to develop area estimates.

Figure **4-2** provides an example for a portion of the Huangpu EDZ in which the urban area has been disaggregated into separate industrial versus residential/commercial/institutional areas.

Randomly-selected grid squares from the area of interest can be analyzed to determine the area of rooftop and open space within each sample square. The drawing and spatial analysis tools within the GIS software allow the user to draw polygons on the rooftops or open space in that square, as shown in Figure 4-3, and then produce area values for each. The percentage of the grid square covered by rooftop or open space can then be applied to the entire area. **Figure 4-4** provides an example of rooftop areas identified by sector using QGIS within the Huangpu EDZ.

**Figure 4-1. Urban Land Maps for the Huangpu EDZ, Guangzhou**. Panel 1: Land cover data, urban land shown in red. Panel 2: Urban land cover manually corrected based on satellite image. Panel 3: Grid squares created in urban area, yellow squares show random selection of grid squares.



The number of grid squares needed for each category of space in the stratified sample (such as industrial rooftop, residential open space, etc.) is dependent on the standard deviation of the calculated area percentage. Therefore, an initial sample must be selected and analyzed to determine the final sample size. The number of samples determined by the formula:

$$N = \left(1.96 * \frac{RSD}{E}\right)^2$$

where:
N = sample size;
RSD = relative standard deviation;
E = error level, for example, 0.1 for error level of 10%.

**Figure 4-2. Example Disaggregation of Urban Area into Sector Zones**. Southern portion of Huangpu EDZ showing a separation of industrial (light purple) and residential/ commercial/ institutional zones (darker purple).

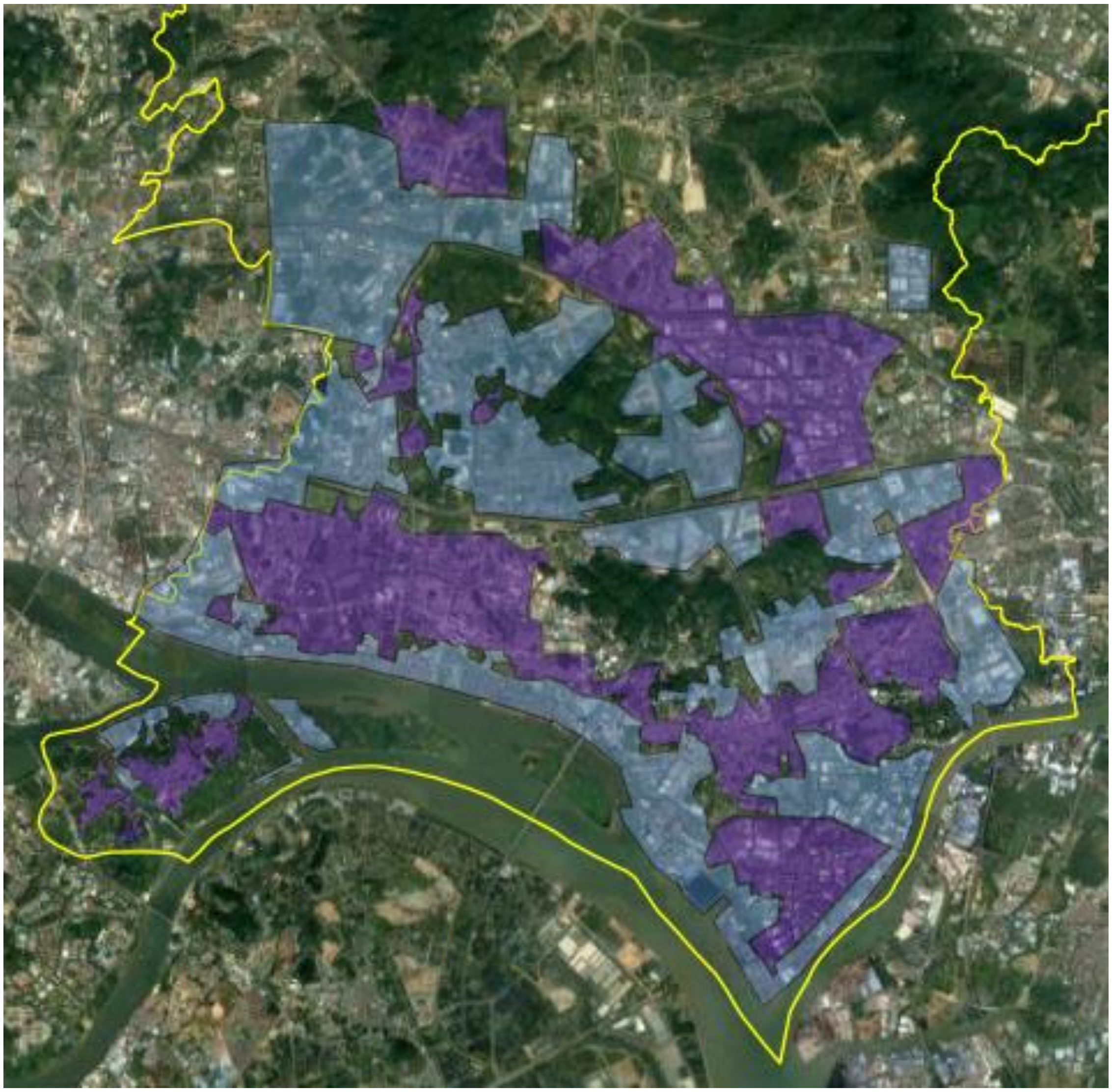
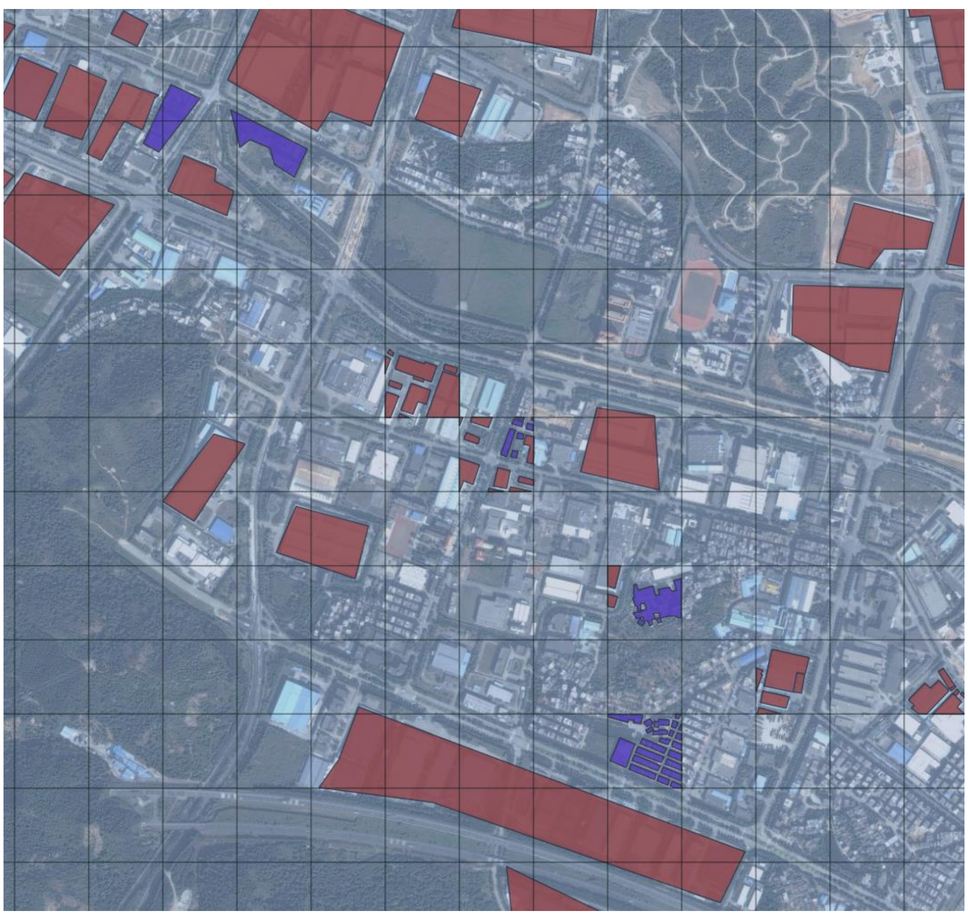


**Figure 4-3. Digitizing Rooftops Using GIS Drawing Tools**

**Figure 4-4. Example GIS-Based Rooftop Area Assessment for the Huangpu EDZ.** The image shows the polygons which were drawn in QGIS with different colors indicating the type of building in the Huangpu district: Red = industrial buildings; Purple = residential buildings; and Yellow = commercial and institutional buildings.



**Considerations for supply assessments of other RE resources.** The spatial analysis methodology applied at jurisdictional scale for the initial characterization of an REZ and the applicable local resource assessments done at this step are dependent on the category of renewable energy. The methodology used to understand solar resource potential is much different than for biomass, for example. This is because biomass resource potential definition requires an assessment of available energy feedstocks (for example, crop residues, purpose-grown crops, forest residues, urban solid waste), feedstock processing requirements (such as chipping, shredding, and/or pelletization), transport needs (such as truck, rail or ship), and energy conversion processes required (such as industrial boiler, biomass power plant, residential space heaters, or biofuels conversion technologies). On the other hand, for solar energy, there is only one energy “feedstock” involved (solar radiation), which is provided by nature directly to the energy conversion process. Additionally, for solar, when the energy product (heat or electricity) is not used immediately on-site, then some consideration of transmission/distribution and/or storage is needed). For other RE resources, examples of local resource assessments could be:

- Biomass: calculate areas of agricultural land by crop type or production of specific agricultural product, or livestock population, within a specified radius around a proposed location of a biomass generation unit; calculate seasonal or annual production of each agricultural by-product that meets the fuel specifications of the energy demand of interest (e.g. biomass power plant; industrial boiler); identify optimal biomass processing locations and transport modes;
- Micro-hydro: calculate potential electricity generation based on elevation change and streamflow characteristics along streams and rivers in a specific local demand jurisdiction, or for inter-connection with the power grid;
- Wind: calculate amount of area of suitable land cover, elevation, and wind speed within a specified distance of transmission infrastructure or localized demand.

# Chapter 5. Selection of Technology Application

An RE Technology Application Multi-Criteria Assessment (MCA) Scoping Tool was developed to assist analysts and/or expert stakeholders to identify and prioritize the most promising technology applications for the local area. Inputs to the tool include those developed from the local area assessment above (for example, available space for implementation of the technology), and cost and performance data from the literature and other modeling tools (e.g. RETScreen[15]). In addition to these empirical or quantitative inputs, the tool also supports the assessment of expert ratings for more qualitative criteria for each technology application. These are based on analyst or expert stakeholder input on performance criteria such as: alignment with jurisdictional/ national objectives (such as RE energy targets); energy security; GHG emissions; and local job creation.

Empirical scoring from the tool currently addresses the following four criteria:

- **Levelized Cost of Electricity (LCOE) ($US/kW):** estimated based on capital and operations and maintenance (O&M) costs, capacity factor, and utilization factor. LCOE is one of the most widely used metrics for comparing the costs of different electricity generation technologies.
- **Lifetime Production (MWh)**: estimated based on the maximum installed capacity potential, and the life expectancy of the given technology application's equipment.
- **Annual GHG Reduction (t$CO_2$e):** estimated based on the annual energy production estimated for the technology and local marginal carbon intensity of grid electricity.
- **GHG Abatement Cost Effectiveness ($/t$CO_2$e):** estimated based on the annual GHG reduction and annualized capital and O&M costs.

Expert rating scores address six criteria. Each criterion is assigned a value from 0 to 5, with 5 indicating that the criterion is applicable and could be significantly improved through implementation of the technology application. The qualitative criteria currently considered in the MCA Scoping Tool are:

- **Alignment with Nationally-Declared Contribution (NDC) or Similar National Goal:** implementation of the technology fits in with the national government's approach to fulfilling its Nationally-Declared Contribution to the Paris Accord (NDC) or similar national objective.
- **Air Pollution Benefits:** implementation of the technology would offset current or expected fossil-based generation that negatively impacts air quality in the planning jurisdiction.
- **Government Financial Support:** the provincial or national government has financial support mechanisms available to support implementation of the technology.
- **Other Environmental Benefits:** implementation of the technology would provide other (non-air pollution) benefits: for example, water quality, solid waste, land use.
- **GSP/Jobs:** implementation of the technology is expected to support local (within planning jurisdiction) employment and economic growth (gross state product or GSP).
- **Energy Security:** implementation of the technology will increase the diversity of energy supply sources and/or reduce energy imports.

**Figure 5-1** and Figure 5-2 below are charts produced using the MCA Scoping Tool based in part on the local area assessment for the Huangpu EDZ. These include quantitative and qualitative scores for 6 different technology applications considered for implementing a solar PV program in the Huangpu EDZ. In **Figure 5-1**, each technology is given a score between 1 and 10 based on the values calculated for the 4 quantitative criteria. **Figure 5-2** provides a visualization of both quantitative criteria and qualitative

[15] http://www.nrcan.gc.ca/energy/software-tools/7465.

scores based on expert judgment of the analysts. The y-axis shows the LCOE calculated for each technology, the x-axis shows the calculated Lifetime Production for each technology, and the bubble size indicates the total Qualitative Performance rating (sum of all qualitative scoring provided by an expert review panel).

**Figure 5-1. Technology Quantitative Multi-Criteria Ranking**. Technology applications are identified within the MCA Scoping Tool by a technology code: Sector (R = Residential, C = Commercial/Institutional, I = Industrial); Technology (PV = photovoltaic); Application (R = rooftop, OS = open space); System Type (F = fixed).

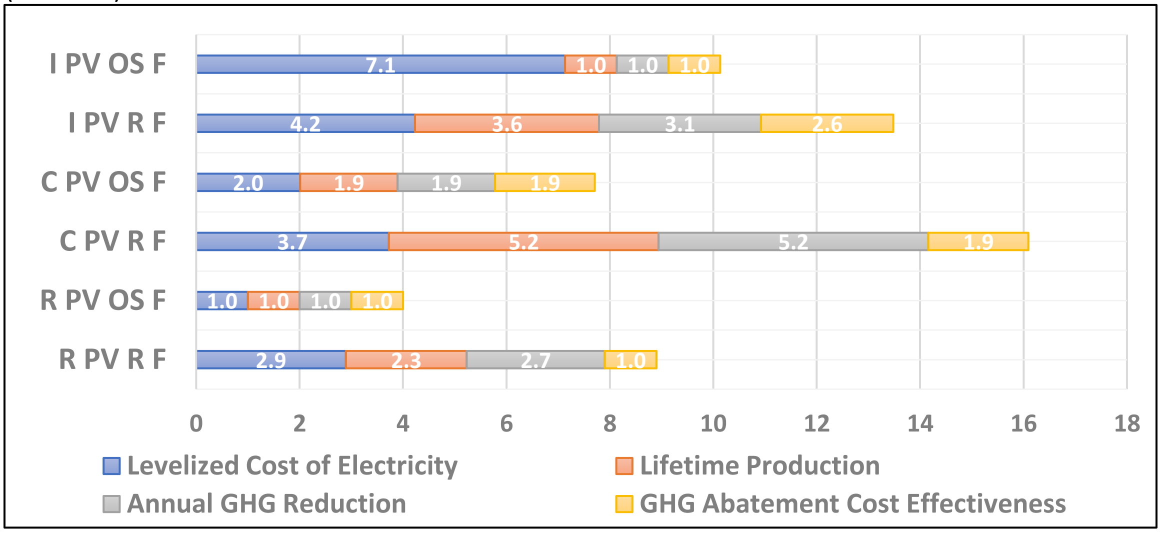
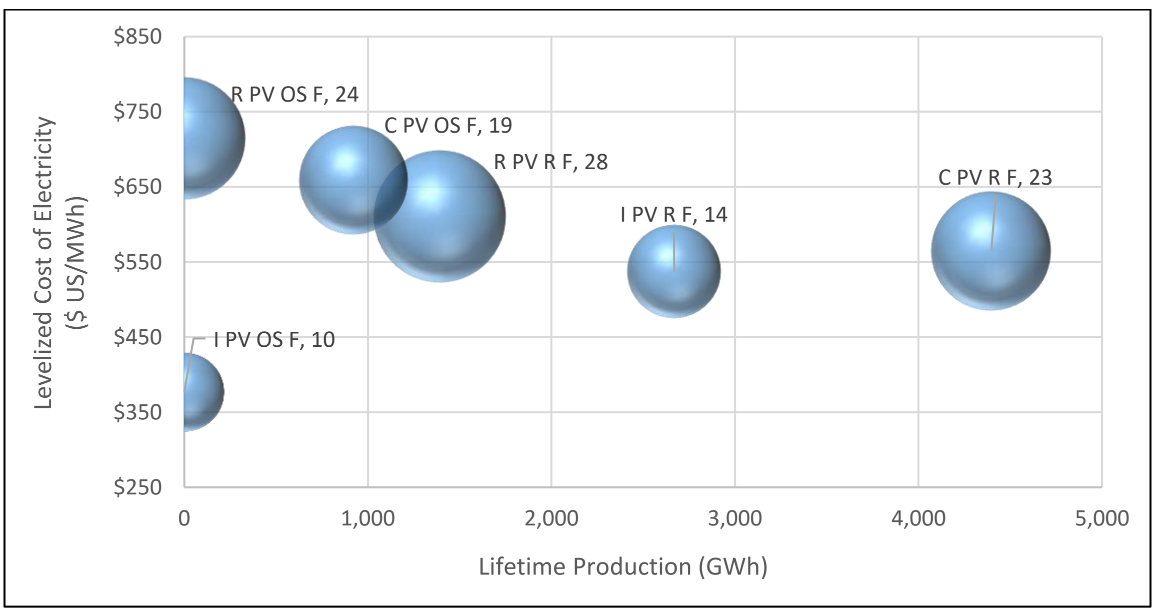
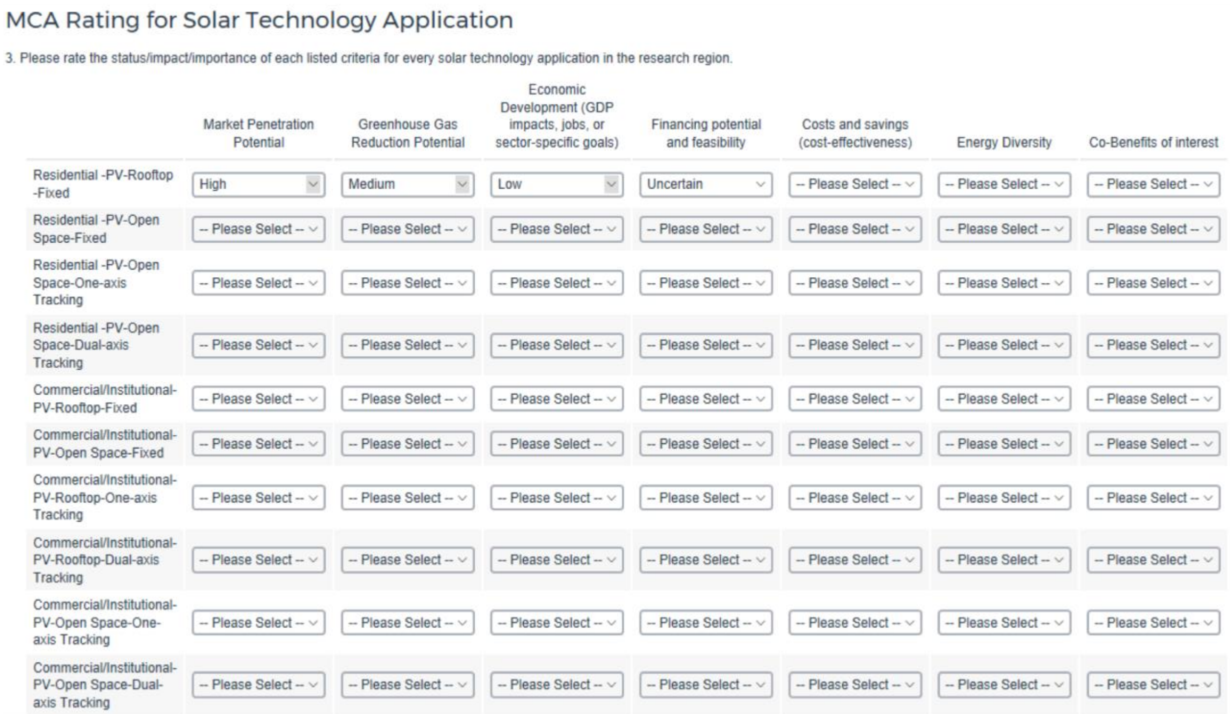



**Figure 5-2. Combined Quantitative and Qualitative Analysis**. In this chart, the size of the bubble represents the total qualitative indicator scoring (value also indicated in the bubble label). Bubbles that end up low on the chart and the furthest to the right indicate applications with the lowest cost and greatest production potential. The application with Code CPVRF (Commercial/ Institutional rooftop photo-voltaic panels) shows the best combination of cost and production criteria in this example.



While output from the MCA Scoping Tool can be used to inform selection of technology applications by a group of analysts, it can also be used to inform an expert group that is charged with making these selections. Such a group then would use the output as background information, and, combined with their own expertise in renewable energy technology, prioritize the selections for local implementation. CCS developed an RE Screening Survey Tool to support the acquisition of expert opinion and to score those rankings. GIEC conducted a survey of local solar energy experts from representatives of academia, government institutes, and industry. Figure 5-3 provides a screenshot of the MCA Survey Tool used to conduct the survey.

**Figure 5-3. MCA Screening Survey Screenshot**



MCA Rating for Solar Technology Application

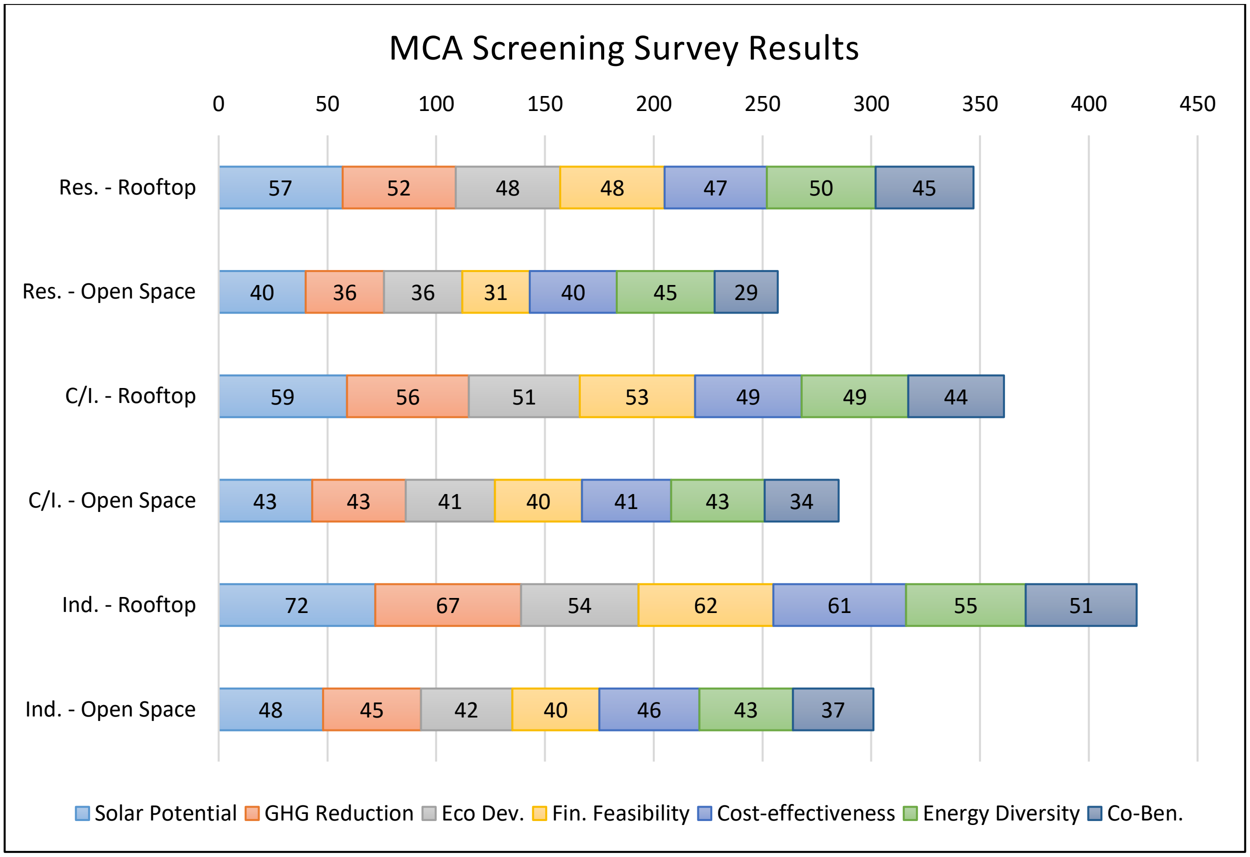
3. Please rate the status/impact/importance of each listed criteria for every solar technology application in the research region.

| | Market Penetration Potential | Greenhouse Gas Reduction Potential | Economic Development (GDP impacts, jobs, or sector-specific goals) | Financing potential and feasibility | Costs and savings (cost-effectiveness) | Energy Diversity | Co-Benefits of interest |
|---|---|---|---|---|---|---|---|
| Residential -PV-Rooftop -Fixed | High | Medium | Low | Uncertain | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Residential -PV-Open Space-Fixed | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Residential -PV-Open Space-One-axis Tracking | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Residential -PV-Open Space-Dual-axis Tracking | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Commercial/Institutional-PV-Rooftop-Fixed | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Commercial/Institutional-PV-Open Space-Fixed | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Commercial/Institutional-PV-Rooftop-One-axis Tracking | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Commercial/Institutional-PV-Rooftop-Dual-axis Tracking | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Commercial/Institutional-PV-Open Space-One-axis Tracking | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |
| Commercial/Institutional-PV-Open Space-Dual-axis Tracking | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- | -- Please Select -- |

Figure **5-4** provides the summarized results of the MCA survey of the expert group members. Prior to the survey, further local area RE assessment indicated a much higher level of technical potential for industry sector rooftop PV area than previously indicated (as indicated by Figures 5-1 and 5-2 above). The additional assessment indicated that industrial rooftop technical potential was significantly greater than either commercial/institutional or residential rooftop area. This information was shared with survey respondents.

In summary, this experience gained from the Huangpu pilot indicates that a purely empirical assessment of local-scale RE application potential might not be sufficient to make the best prioritization of technology applications for implementation. The additional local knowledge and technical judgment of an expert group should be leveraged to best focus implementation of RE opportunities.

**Figure 5-4. Results from the MCA Screening Survey**. Industrial rooftop PV systems edged out commercial/institutional and residential rooftop systems as the technology application with the highest priority for implementation in the Huangpu EDZ.



# Chapter 6. Business Model Development

A Business Implementation Model for the Huangpu EDZ Industrial Rooftop Solar PV Program was developed using a standardized documentation template developed during the project (see Attachment B). The Business Implementation Model documents each implementation phase and its individual steps, agreements, actions, mechanisms, parties responsible for completing each step, analytical requirements, and specific deliverables/outcomes. In addition, the documentation template, referred to as the "Technology Implementation Document" or "TID" by the project team, documents the expected impacts (energy supply/demand, GHG emissions, other co-benefits), financial and risk analysis, and linkages to any regional cap and trade program. This chapter presents portions of the TID for the Huangpu Program with a focus on the Business Model itself.

## a. Technology Application Description

Solar photovoltaic (PV) power systems for the industrial sector provide carbon-free electricity for use in industrial processes and/or buildings, and potentially, during periods when production is in excess of facility needs, for other electricity consumers. Solar PV systems use flat or, in future designs, even curved PV panels or PVs built into building materials to capture the energy and sunlight and convert it directly to electricity. Solar PV systems are practically infinitely scalable, ranging in size from a few watts to charge a mobile phone or other small device, to tens or hundreds of megawatts for utility-scale systems, though typical industrial-scale systems would be in the tens to hundreds of kilowatts size range.

Solar PV panels can be mounted on buildings, placed on support structures built on vacant land, or incorporated into infrastructure such as parking lots, retaining walls, bridges, and other structures, wherever a relatively unobstructed southern (in the northern hemisphere) exposure is available. Solar PV systems, because their peak output generally occurs when temperatures are warmest and power use for air conditioning, particularly in a climate like South China’s, is near peak levels, can help to relieve peak power demands on both electricity supply systems and local transmission and distribution grids, depending on how the systems are configured and the locations of the projects.

A local resource assessment for the Huangpu EDZ conducted by the research team and input from a local expert group on solar power identified industrial rooftop PV applications to have the highest priority for implementation. From the local resource assessment, the technical potential for industrial rooftop solar PV in the Huangpu EDZ was estimated to be 505 MW. Therefore, this TID focuses on an implementation (or business) model for implementation of industrial rooftop PV systems. The Huangpu district has planned to install 302 MW solar PV capacity in any form across all building sectors by 2020. However, there has been limited progress on the implementation of this technology. The current installed capacity is less than 50 MW as of 2015. Under BAU conditions, the project team estimates that the total installed capacity of solar PV will be 185 MW by 2020 (these represent installations after 2015, including those in the development pipeline through 2020). Even if all of this BAU capacity was installed on industrial rooftops, an additional technical potential of 320 MW is available based on our local area assessments. Considering the implementation period included for this program (through 2025), if the program is successfully implemented according to the Business Model, it will tremendously help the Huangpu district to achieve its existing solar PV installation target by 2020 as well as additional capacity through 2025.

There are at least three basic ways that industrial rooftop solar PV systems can be configured. The first, and most common in nations where electricity grid systems are well-established, is a grid-connected configuration where PV panels either provide power directly to the grid, and the industrial facility purchases power back from the grid to meet daily needs, or where solar PV power goes first to meet the needs of the facility, and any excess is sold to the grid. In either case, the electricity grid provides power during those times when there is insufficient electricity production by the PV system to meet facility needs. The second type of system is a grid-independent or “off-grid” system, where PV power is used for industry needs but also charges a battery or other energy storage device, to be drawn upon when direct power from the PV system is not available or insufficient. The third type of system can be thought of as a hybrid, whereby a number of facilities share a PV system and share electricity/energy storage in a “micro-grid” configuration, which may be supplemented by a non-solar power source, such as a gas turbine or diesel engine-generator, and/or supplemented by some imports of grid power. In the Huangpu EDZ, in which all industrial facilities are likely connected to the electrical grid, the first and third of these options are likely to be the most practical.

With a presumed average size of 2.5 MW per system, the program will address about 130 solar PV systems to achieve the program goals. The projects themselves will be at the individual facility or building scale. Individual projects will be targeted to one or more types of markets for industrial solar PV in the Huangpu EDZ. Differentiation of markets could be by industry subsector or size, existing or new facilities, and location within the EDZ.

Potential sources of finance range from funds provided by each industrial facility owner (equity); to private bank financing (debt); enabling mechanisms, such as utility or government rebates; and/or funds from carbon trading systems. Combinations of these types of financing are likely, and the technology application design and implementation model described below includes the two most likely: 1) solar PV company applies for loans from bank and then provides both installation and financing to the factory owner; or 2) factory owners apply directly to the banks for loans and contract separately with the solar PV company. Note that for the first option, it is also possible that a solar PV manufacturer offers systems, installation, and financing directly to factory owners.

## b. Technology Application Design

This portion of the TID summarizes the numeric targets of the RE project/program, program schedule, details on project/program location, and other supporting information.

**Goals**

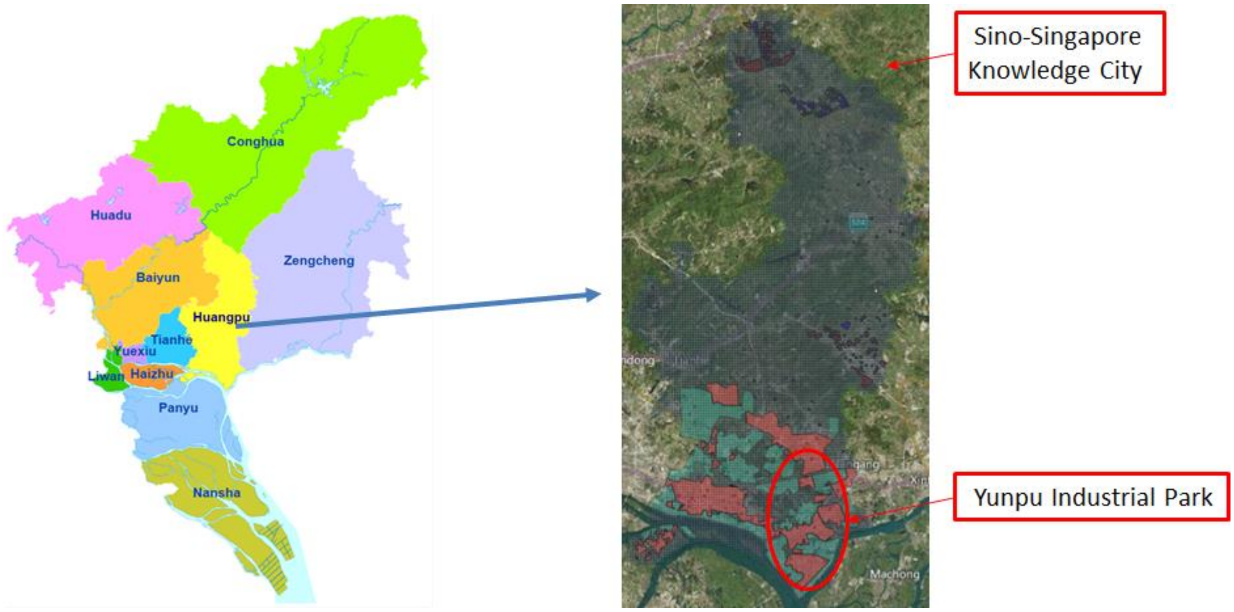
The Huangpu Industrial Solar PV Program will implement 320 MW of solar PV power generation capacity on industrial facility rooftops.

**Location**

Industrial rooftops throughout the Huangpu EDZ.

Figure **6-1** provides an overview of the EDZ. Most of the near term (through 2020) opportunities will occur in the southern portion of the EDZ, where the industrial base is already established. The Sino-Singapore Knowledge City development in the northern portion of the EDZ is where opportunities are currently emerging as this area is further constructed. It is expected that many of the installations in this area will occur later in the program (e.g. between 2020 and 2025).

**Figure 6-1. Map of the Huangpu EDZ**. Key areas for program implementation are in the Sino-Singapore Knowledge City (currently being constructed in the northern portion of the EDZ) and the Yunpu Industrial Park.




**Timing** The Program will run from 2018 – 2025. Industrial rooftop PV installations will total 117 MW by 2020 and the total program goal of 320 MW by 2025.

**Other**

The timing for installations above recognizes that opportunities exist for new industrial buildings being constructed as part of the Sino-Singapore Knowledge City in the northern portion of the EDZ, as well as existing industrial roof space in the southern portion (especially the Yunpu Industrial Park).

Expected business as usual (BAU) installations of PV systems in the EDZ are 185 MW by 2020. Most of this capacity has been built within the industrial sector. Of this expected capacity in 2020, 72 MW were installed by 2016 and another 113 MW is estimated to be in the development pipeline. The Program goals represent installations expected above and beyond BAU installations up to the estimated technical potential for industrial rooftop solar PV estimated from the local area supply assessment (505 MW). This includes about 117 MW of industrial rooftop solar PV by 2020 (320 MW including BAU installations) and another 203 MW by 2025 (505 MW total including BAU installations).

The total Huangpu EDZ program is 320 MW of capacity above and beyond BAU by 2025. The largest areas for installations within the Huangpu EDZ are the Sino-Singapore Knowledge City (155 MW) and the Yunpu Industrial Park (70 MW). At an estimated average size of 2.5 MW per system, the total program will address about 130 individual projects. The Project Team recognizes that 505 MW of technical potential represents an upper bound of industrial rooftop PV potential, since this value has not yet been corrected for shading or technical feasibility of installations on all industrial rooftops.

## c. Implementation Model

The Implementation Model (sometimes also referred to as the "business model") for the Program is summarized in Table 6-1 below following a graphical summary in Figure 6-2. The Implementation Model is divided into 7 phases. Within each phase, the discrete steps (legal, policy, administrative, and financial mechanisms) that need to be addressed by a specified party are also listed. Additional details on the implementation phases are provided in the section below.

The Business Implementation Model for the Huangpu EDZ Industrial Rooftop PV Program features two different financing options. From the perspective of a factor owner, financial model 1 represents the simplest option. In financial model 1 (red), the solar PV company obtains loans from a bank and then provides all services directly to the factory owners (design, installation, follow-on O&M). In financial model 2 (blue), factory owners obtain bank loans, and then contract separately for system design and system installation/O&M. The Power Supply Bureau of Huangpu would purchase power supplied to the grid from either the factory owner or solar PV company, depending on the financial model used.

**Figure 6-1** provides a summary of the Business Model with a focus on the financial flows of the two different lending models.

**Figure 6-2. Huangpu EDZ Industrial Rooftop PV Program Business Model**. The Business Model features two different financing options. In financial model 1 (red), the solar PV company obtains loans from a bank and then provides all services directly to the factory owners (design, installation, follow-on O&M). All power is sold directly to the grid operator and a revenue sharing agreement is made between the factory owner and solar PV company. In financial model 2 (blue), factory owners obtain bank loans, and then contract separately for system design and system installation/O&M. The local power utility purchases excess power for the grid from the factory owner in financial model 1.

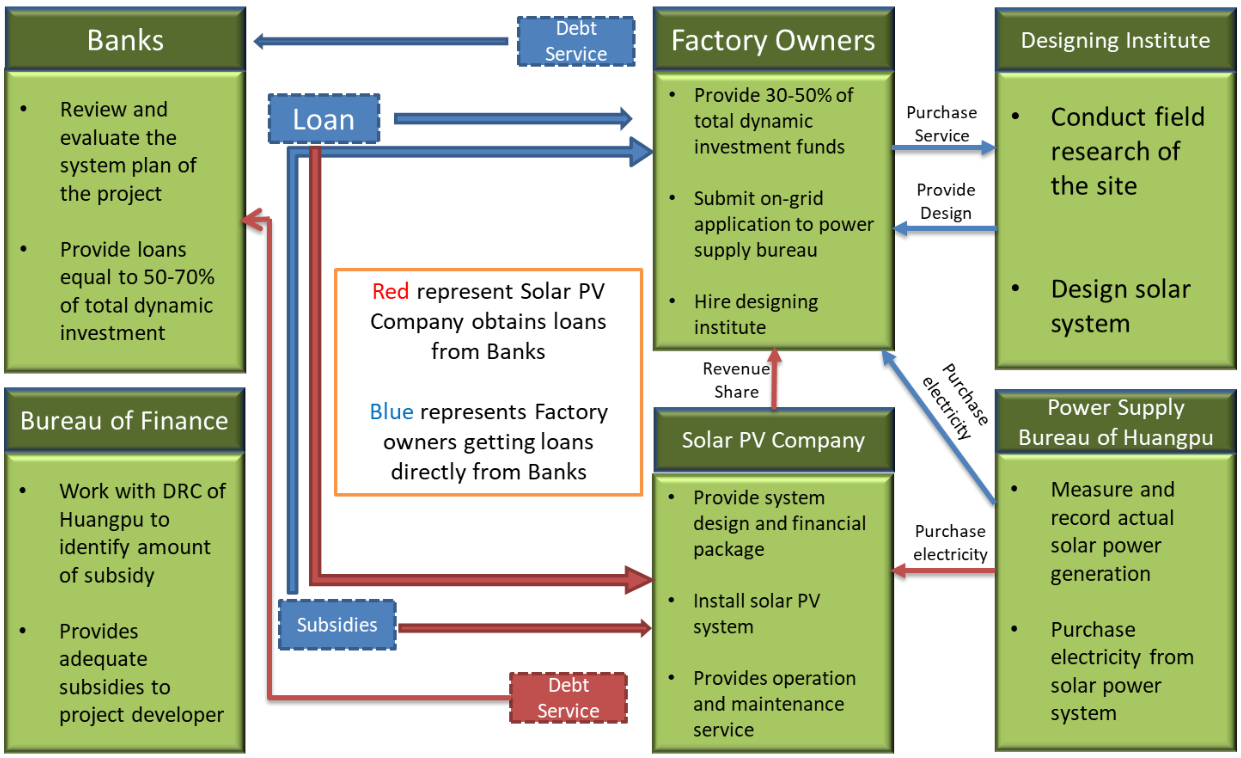


**Table 6-1. Implementation Model for the Huangpu Industrial Rooftop Solar PV Program**

| Phase | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Phase Name** | **Complete Program Feasibility Assessment** | **Partner Assembly** | **Program Marketing** | **Define Projects** | **Program Funding** |
| **Parties Involved** | • GIEC<br>• Power Utility<br>• Power supply bureau of the Huangpu district | • GIEC<br>• Industrial Facility Owners<br>• Solar PV Company<br>• Bank<br>• Guangzhou DRC<br>• Power supply bureau of the Huangpu district | • GIEC<br>• Solar PV Company<br>• Industrial Facility Owners | • Solar PV Company<br>• Industrial Facility Owners<br>• GIEC | • Bank<br>• Industrial Facility Owners<br>• Guangzhou DRC<br>• Solar PV Company |
| **Steps: Legal, Policy, Administrative, and Financial Mechanisms** | 1. GIEC works with the Power supply bureau of the Huangpu district to assess technical feasibility of integrating the new distributed generation achieved by the program.<br>2. GIEC and Power supply bureau of the Huangpu district address any identified feasibility issues. | 1. GIEC presents the Program and its expected impacts to each partner and gains their support for the program and agreement on their role, timing, etc.<br>2. Solar PV Company prepare a standard financing package(s) to facility owners. | 1. Solar PV company conducts the marketing program to facility owners.<br>2. GIEC and Solar PV company provide support to interested facility owners to understand the benefits of the program. | 1. Solar PV Company provide proposals to Facility Owners.<br>2. GIEC provides technical support to Facility Owners to evaluate proposals.<br>3. Facility Owners select a winning bidder among the proposals submitted (contingent on receipt of funding) | 1. Solar PV Company completes the financing package and sends it to Facility Owner. Solar PV Company provides support to Facility Owners to understand the package.<br>2. Facility Owner reviews and conducts any follow-up with Solar PV Company.<br>3. Facility Owner signs designing and business contract(s).<br>4. Lending Institution provides funds to Solar PV Company consistent with contract requirements.<br>5. Guangzhou DRC can apply the distributed PV power generational subsidy for the project. |

| Phase | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Phase Name** | **Complete Program Feasibility Assessment** | **Partner Assembly** | **Program Marketing** | **Define Projects** | **Program Funding** |
| **Analytical Requirements** | • GIEC: Detailed local industrial electricity demand and solar PV supply assessment<br>• Power supply bureau of the Huangpu district: Integration assessment of new solar power with the local grid | • GIEC and Solar PV Company: Additional financial and other risk analyses for projects of different types of Industrial Owners (state-owned enterprise, listed companies or private enterprises) and product (explosive or corruptive materials). | • GIEC and Solar PV company develops a listing of industrial facility contacts for marketing the program | • Solar PV Company develop preliminary design and cost estimates for use in their proposals to Facility Owners. | • Facility Owner reviews design and cost proposals from Facility Owner or GIEC complete standard financial analysis (e.g. using the Financing Tool) for inclusion in the financing package. |
| **Other Requirements** | | | | | |

**Table 6-1. Implementation Model for the Huangpu Industrial Rooftop Solar PV Program(cont.)**

| Phase | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|
| **Phase Name** | **Program Implementation** | **Program Scale-Up** | | | |
| **Parties Involved** | • Industrial Facility Owners<br>• Solar PV Company<br>• Guangzhou DRC Power supply bureau of the Huangpu district | • GIEC<br>• Guangdong DRC<br>• South China Power Grid<br>• Industrial Facility Owners<br>• Solar PV companies | • | • | • |
| **Steps: Legal, Policy, Administrative, and Financial Mechanisms** | 1. Industrial Owners get approval of the China South Power Grid to build their solar PV installation<br>2. Solar PV Company install PV systems for Facility Owner.<br>3. Connect the solar system on the grid. | 1. Contact and assemble the factory owner that listed in the Guangzhou Distributed Solar PV Generation Planning<br>2. Contact the power supply bureau of other districts.<br>3. Solar PV company and GIEC do the Phase 1- 6 in a city scale and even provincial scale in the future. | | | |
| **Analytical Requirements** | • Guangzhou DRC do the project recording and information gathering of the project. | | | | |
| **Other Requirements** | | | | | |

# Chapter 7. Financing and Risk Analysis

The REI Toolkit includes a Financial Analysis Tool developed in MS Excel. The tool is based around the discounted net cash flow (DNCF) analytical approach. DNCF is one of the preferred valuation methods in financial theory and practice, which estimates the present value (or performance) of an investment (a project, a facility, a stock, a company, a fund, etc.) that generates cash flows over its lifetime. This requires projecting cash outflows (costs) and inflows (benefits) expected to be achieved by the investment in the future years, which are then discounted by the application of a pre-determined discount rate, in order to evaluate their present value (worth of future value to the investor in present terms).[16]

Discounting is applied to account for:

1. Human time preference of benefits (that is, benefits received today are preferred to the benefits received next week, month, year, or at some other point in the future), even if the future benefits are assumed to be absolutely certain/guaranteed. This becomes especially relevant for the classes of investors who aim to rapidly recover the capital and achieve the desired profit in order to reinvest the funds into other assets.
2. Uncertainty and risk surrounding the benefits received in the future time periods, where the conventional reasoning implies that the more distant the expected realization of the future cash flows (both positive and negative), the more uncertain they become.

The Financial Analysis Tool assists the user in defining and assessing the estimated benefits and costs applicable to a technology application program/project in annual increments. Benefits include revenue from power sales (as influenced by any feed-in-tariffs), renewable energy credits revenue, and other revenue. Costs include total installation costs, equity, debt service, fuel costs, fixed and variable annual costs, taxes, and others. Using a user-specified discount rate (which, in nominal terms should account for inflation, plus the cost at which the value of capital invested in a program/project is reduced due to time preference), the tool calculates standard indicators of financial performance:

- **Net Present Value (NPV)** is the sum of present values of all future benefits and costs realized by a program/project, reduced by a sum of present values of all the future costs. The mathematical expression for NPV is:

$$\mathrm{NPV} = \sum_{t=0}^{n} CF/(1+R)\hat{}t$$

where:
*CF* = a benefit/cost achieved at time *t*;
*R* = the discount rate; and
*n* = the number of years of the lifetime of the project.

The present value of each future benefit/cost is calculated according to the following formula:

$$P = F/(1 + R)^t$$

[16] J. Schill, M. (30 May 2017 ). Discounted Cash Flow Analysis. *University of Virginia, Darden School of Business*.

where:
P = the present value;
F = the future value;
R = the discount rate; and
*t* = the future year in which the benefit/cost is expected to occur.

If only one project's financial performance is a concern (without consideration of alternatives), then NPV>0 indicates that the project is financially viable. If multiple projects are evaluated, the one with the highest NPV should be pursued.

- **Internal Rate of Return (IRR)**, the discount (or interest) rate at which the net present value of the project equals 0. The condition is mathematically expressed as $\mathrm{NPV} = \sum_{t=0}^{n} CF/(1+IRR)^\wedge t = 0$.

  If the IRR of a program/project is higher than the discount rate (or target interest rate for the investment), then the project can be considered financially viable. If multiple projects are evaluated, the one with the highest IRR would typically be pursued first, assuming the candidate projects' performance with regard to other financial and non-financial criteria are similar.

- **Return on Investment (ROI)**, which is the sum of all the discounted benefits reduced by the sum of all discounted costs over the lifetime of the project, divided by sum of the discounted costs. ROI captures the relative scale of a program/project's returns and costs while accounting for uncertainty embedded in the passage of time.

- Other common financial performance parameters: simple payback period, benefit-cost ratio, and levelized cost of electricity (LCOE). For example, while the financial analysis for the Huangpu Industrial Solar Rooftop Program is still ongoing, initial estimates for simple payback using Financial Model 1 (factory owner system with excess power sold to grid) was estimated to be 8.4 years; while for Financial Model 2 (solar PV company owned system with revenue share to factory owner), it was estimated to be just over 10 years.

The financial analysis tool also provides the user with an ability to perform an introductory level sensitivity and risk analysis, whereby the level of sensitivity of output financial indicators to the variability/uncertainty in input parameters (i.e., power sales price, installation costs, fuel costs, etc.) is evaluated. As of the writing of this report, the financial analysis for the Huangpu Pilot Project is still ongoing.

**Figure 7-1** provides a sample summary of a DNCF analysis prepared for a rice husk power plant implemented in Thailand (see Attachment D for details on the DNCF). **Figure 7-2** provides a sensitivity analysis of estimated IRR for three key input variables: power sales price; total installation costs; and biomass fuel price.

**Figure 7-1. Example DNCF for a Biomass Power Plant Project**. Costs address initial installation (capital) costs, fixed O&M, fuel, and other variable O&M. Revenues (benefits) include revenue from power sales and the local feed-in-tariff paid for renewable power production.

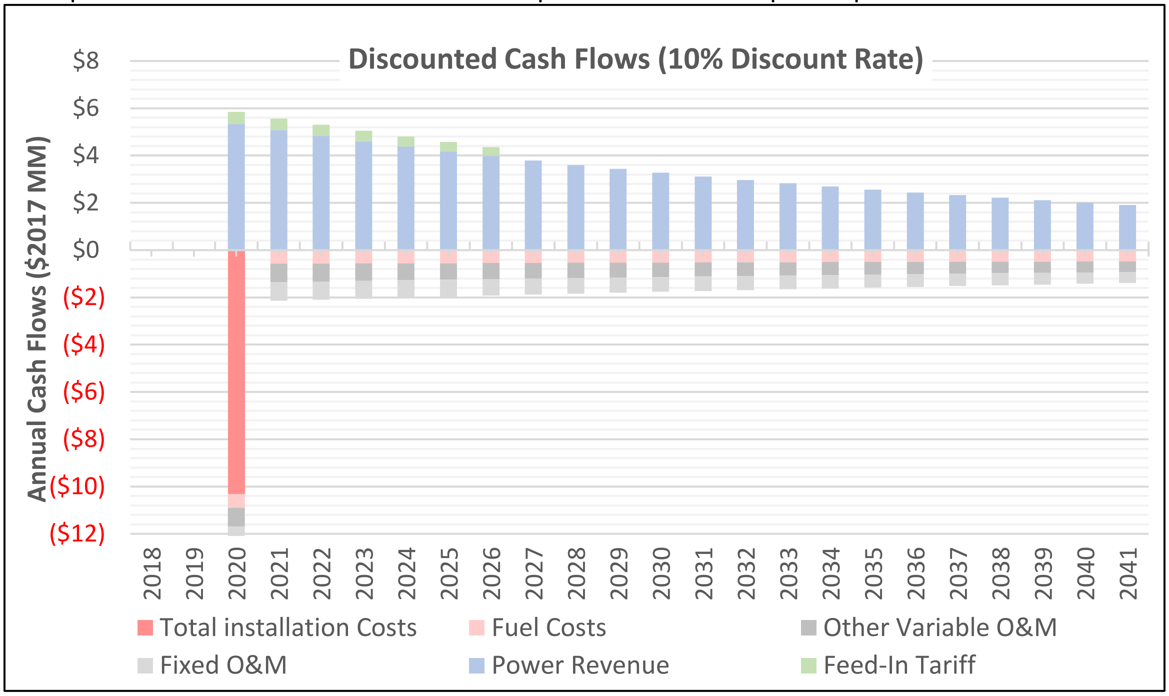
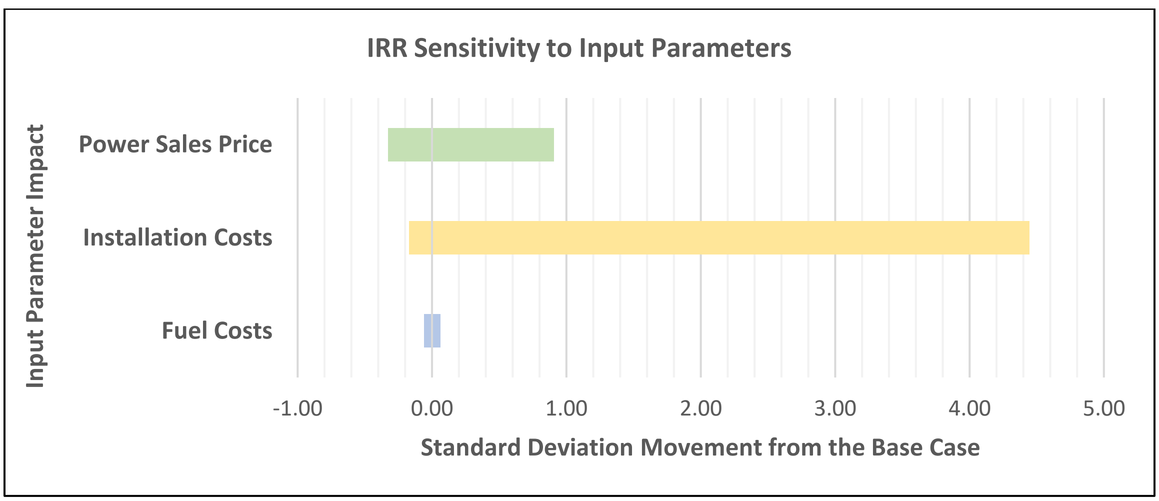



**Figure 7-2. Biomass Power Plant IRR Sensitivity to Key Input Parameters**. Uncertainties in installation costs had the greatest impact on estimated IRR. Power sales price was also found to be a relatively strong driver in estimated IRR.



# Chapter 8. Next Steps

Based on the experience gained by the Project Team in developing the Toolkit and piloting its application, following are the next steps to be taken:

1. Complete final analysis and documentation of the Huangpu EDZ Pilot: this includes completion of financial analysis for one or more model systems installations and the impacts analysis (energy, environmental, linkage to cap and trade);
2. Implementation of the Huangpu EDZ pilot: as documented in the Business Model, this includes initiating agreements with the key players; program marketing to industrial facility owners, lenders, and solar project developers; and providing technical support;
3. Pilot program scale-up to the provincial scale: use of the pilot approach in other EDZs and targeted local areas in Guangdong province;
4. Expansion of the REI Toolkit to other RE resources: especially other forms of solar (concentrated plants), wind (mainly onshore in Guangdong province), and biomass (e.g. agricultural residues); pilot program/project application in the relevant local areas;
5. Expansion of REI Toolkit application to other parts of China and beyond through similar "learning-by-doing" partnerships in other provinces and countries.

# Attachment A. LCD Toolkit Description

The LCD Toolkit includes a number of tools, listed in Table A-1 below, for estimating baseline conditions (energy, natural resources, materials management, emissions), selecting and designing mitigation policies (by economic sector), and conducting micro- and macro-economic modelling of those policies. The baseline modules for each economic sector (Energy Supply, Residential, Commercial, and Institutional Fuel Use; Industrial Processes and Fuel Use; Transportation; Agriculture, Forestry and Fisheries; and Waste Management) are Excel-based workbook tools for developing historical and forecast business-as-usual (BAU) baselines at the subnational level (e.g., provinces, states, sub-state regions, municipalities). The Synthesis Module combines all sectors to create and economy-wide baseline emissions inventory and forecast. The Synthesis Module also combines analyses of mitigation policies and compares the combined results of these policies to the baseline.

Development of mitigation policies begin with the policy catalog for each sector, which provides possible policies that can be selected for analysis. A policy design document template provides a framework for developing the details needed for analysis of costs and GHG impacts of the chosen policies. Policies can then be analyzed using the Microeconomic Quantification workbooks. Results of the microeconomic analysis are combined with the baseline results in the Synthesis Module to provide economy-wide costs and GHG impacts.

**Table A-1. Low Carbon Development (LCD) Tools**

| Tool | Function |
|---|---|
| *Energy, Economic and GHG Baselines* | |
| Energy Supply Module | Excel-based workbook templates for estimating historical and forecast GHG emissions and energy consumption; guidance documents covering sector-level approaches to forecasting. |
| Residential/Commercial/Institutional | |
| Industry | |
| Transportation | |
| Agriculture, Forestry, and Other Land Use (AFOLU) | |
| Waste Management Module | |
| *Policy Selection & Design* | |
| Policy Catalog | Catalog listing possible policies specific to each Sector. |
| Multi-Criteria Selection Surveys | On-line survey tool to gather expert input on policy performance against qualitative and quantitative criteria. |

| Tool | Function |
|---|---|
| LCD Policy Design Template | Document template providing framework for policy design and analysis. |
| *Microeconomic Analysis* | |
| Common Forecast Data Workbook | Excel-based workbook template for collecting data important for forecasting and microeconomic analysis, including population growth, GDP growth, marginal energy costs and carbon intensity. |
| Policy Impacts Analysis Guidance | Including example Quantification memoranda that describe the specific approaches to be taken to quantify direct policy impacts (energy, emissions, costs). |
| Sector-Level Quantification Workbooks | Excel-based workbook templates for each sector for estimating costs, energy and GHG impacts of policies. |
| *Synthesis of Results* | |
| Synthesis Module | Excel-based workbook tool that combines results from sector-level baseline and microeconomic analysis modules to create economy-wide energy, emissions and economic impact results. |

# Attachment B. Technology Implementation Document Template

**Technology/Policy Name and Identifying Label/#**

This Technology Policy Implementation Document (TPID) template is used for each draft priority technology/policy option to document its status and the details of its development to support stepwise decision making and transparency needs.

## Option Description

[Provide a general concept description or "overview" of the technology/policy option including its purpose and the rationale behind it and generally how it will be implemented to reach goals, including local feasibility. The "purpose" can also be thought of in terms of its intended effects and will typically fall into one of two categories: technology adoption or change in practice. The "rationale" involves mapping to objectives (e.g. sustainable development, economic vision and goals, equity, others). If the option is related to existing policies in the nation/subnational area, then this should be noted. Typical length: 1-3 paragraphs. Include a general description of the implementation model and its key mechanisms (finance, law, etc.).]

## Option Design and Implementation

[This section outlines the "what you do and how you do it" aspects of the option with a series of breakdowns.]

### Goals

[Specific, clearly defined, numeric metrics that address goals and objectives of the option, with explanation as needed. Goals should be expressed in units appropriate to the policy and its objectives, i.e., % of market penetration and access to technology, number of installations, quantity produced, acres affected, jobs created, risks avoided, etc. These should be achieved over and above existing and planned (business as usual or BAU levels).]

### Location

[Identify specific geographic location and scale.]

### Timing

[Identify start, ramp up, completion, and other any important timing requirements, assumptions or concerns.]

### Other

[Use this to indicate any pertinent option design features or issues not covered above. These could be exemptions or thresholds which include or exclude involved entities.]

### Implementation Model

[Summary description of the overall process by which the option is moved from startup to final implementation, including a diagram that shows each of the steps and the parties involved and requirements needed for each stage of decisions, including metrics in a table with supporting narrative on stepwise procedures.]

**Implementation Model**

| Steps | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| **Phase Name** | Start… | Intermediate… | Intermediate… | Finish… |
| **Parties Involved** | Decision makers and enablers | | | |
| **Legal, Policy, Administrative, and Financial Mechanisms** | Mechanisms | | | |
| **Analytical Requirements** | Metrics | | | |
| **Other Requirements** | If/as needed | | | |

**Planning Procedures**

[identify any additional stepwise planning procedures needed to support the development of the implementation model.]

**Implementation Stages**

[Identify and describe each stage of implementation from start to finish.]

**Parties Involved**

[Identify those affected by outcomes of the option and those involved in its implementation and their roles, including involvement in implementation mechanisms.]

**Implementation Mechanisms**

[Identify and describe the legal, administrative, and financial mechanisms needed for implementation.

- Legal
- Policy
- Administrative
- Financial]

**Requirements**

[Identify and describe the legal, administrative, and financial requirements needed for planning and implementation, including specific metrics.

- Legal
- Policy
- Administrative
- Financial]

## Baseline Conditions

[This should also capture the relevant elements of any existing and/or planned actions at the subnational/national level that affect implementation of the option. Measures are designed to be incremental to existing and planned actions (baselines). Add information that is more detailed regards location and timing. Include a description of any existing program and the relationship to the option (for example, applicable emissions offsets, funding source).]

## Metrics for Implementation Assessment

[Create a general equation followed by the procedure by which it will be customized to the technology/policy measure at broad as well as specific level through use of methods and metrics.]

**Energy Demand**

1. <u>General Methodology</u>

[Include general methods and metrics for the option.]

   a. Regional Long Term (RLT) Energy Demand (ED) = ƒ (regional and decadal kWh, BTU volume)
   b. Local Time and Place Specific (TPS) ED = ƒ (RLT Average +/- TPS Deviations)
      i. ED = ƒ (price and non-price attributes x volume)
         1. Price effect = ƒ (net price/payment plus elasticity)
         2. Non-price effect = ƒ (determinate attributes such as guarantees, co-benefits, plus elasticity)
         3. Volume = ƒ (end use technology, current level of need, growth, flexibility, net import/export
      ii. Volume/Load Growth = ƒ (population, economic and income growth, climate changes, technology innovation, policy incentives (e.g. caps), financial incentives
         1. End use technology = ƒ (lights, fans, A/C, refrigeration, appliances, equipment)
         2. Policy effects

a. Cap effect = ƒ (stringency, baseline GHG intensity, flexibility (e.g. offsets, excess allowance purchase), value of allowances

b. REC effect = ƒ (stringency, flexibility, value of credits)

3. Financial incentives supply = ƒ (return, risk, impact)

4. Net import/export = ƒ (on site generation vs. total consumption)

2. Key Methods

[Include specific methods for the option.]

i. RLT ED calculation

1. Overall methods and metrics

2. Disaggregation parameters:

a. Drivers for time based variation adjustments

b. Drivers for location based variation adjustments

ii. TPS ED deviations

1. Adjustment methods and metrics

a. Time based variation adjustments

b. Location based variation adjustments

3. Key Metrics

[Include specific metrics for the option, including data sources, methods, key assumptions.]

a. Electricity and direct fuels price and elasticity

b. Determinate attributes and elasticity

c. End use technology mix and shifts: lights, fans, A/C, refrigeration, appliances, equipment

d. Population, economic and income status and growth

e. Climate change effects on heating, cooling

f. Technology innovation rates

g. Policy incentives

i. Caps: stringency, baseline GHG intensity, flexibility, value of allowances

ii. RECS: stringency, flexibility, value of credits

iii. Other policies and requirements if/as needed

h. Financial incentives:

i. Risk: governance, market, project

ii. Return: NPV, rate, payback period, level, liquidity

iii. Impact: Public benefit or net social impact

i. On site generation level and growth

j. Others?

**Energy Supply**

1. General Methodology
   a. xxx
2. Key Methods
   a. Xxx
3. Key Metrics
   a. xxx

## Results of Assessment

[This section is where the quantification results are presented and discussed.]

### A. RLT and TPS Energy Demand

[This section will be completed based on the results of the demand/supply assessments, financing, and trading and other ancillary policy impacts. List the relevant metrics and results, perhaps in table to simplify, and then provide a step-wise description of the process used for evaluating metrics.]

- **Direct, Indirect, and Integrative Impacts**
  - [This section is where the summary of results for supply and demand, financing, and trading and other policy impacts can be provided in a table and other summary documentation. This also is where a link or reference to more detailed analysis and results can be found.]
- **Data Sources**
  - [This section is where the quantification data sources are presented and discussed. For instance, it could include energy sales records filed by utilities, etc.]
- **Quantification Methods and Tool**
  - [This section is where the quantification approach and tools used to derive the summarized results are presented and discussed.]
- **Key Assumptions**
  - [This section is where the key assumptions behind the quantification results are presented and discussed (e.g. capital costs, financing assumptions, energy prices, market penetration and uptake rate, etc.).]
- **Key Uncertainties**
  - [This section addresses key uncertainties and any methods for addressing them in quantification results above.]

- **Feasibility Issues**
    - [This section addresses key feasibility issues identified and addressed or not addressed in the assessment and their implications.]

**B. RLT and TPS Energy Supply**

[Use the same template as for Energy Demand, above.]

- Direct, indirect, and integrative effects for key metrics
- Data sources methods, key assumptions, uncertainty, feasibility issues

**C. Financial Incentives**

[Use the same template as for Energy Demand, above.]

- Direct, indirect, and integrative effects including risk, return, and impact
- Data sources methods, key assumptions, uncertainty, feasibility issues

**D. Trading and Other Policies**

[Use the same template as for Energy Demand, above.]

- Direct, indirect, and integrative effects including stringency, flexibility, and values
- Data sources methods, key assumptions, uncertainty, feasibility issues

**Additional Impacts**

[If needed, this section can include outcomes or outputs of analysis that are not included in the quantification section and the metrics it covers, and can include a more limited approach to analysis or qualitative discussion of key impacts.]

**Status of Approvals**

[This reflects the status of the option as it moves through the decision making and assessment process from conception to final recommendation.]

# Attachment C. Technology Implementation Document Sample – Residential Solar PV

**Residential Solar Photovoltaic Power: Bangladesh Solar Home System Case Study**
**[Label/#]**

This Technology Policy Implementation Document (TPID) template is used for each draft priority technology/policy option to document its status and the details of its development to support stepwise decision making and transparency needs.

*Upfront Considerations for Solar Photovoltaic (PV) Power Programs in General:*

- Specification of Type of Solar PV Installations: this example considers three types of installations—grid connected, non-grid connected, and semi-autonomous, such as micro-grids for neighborhoods or developments. A specific program in South China or elsewhere might focus on just one of these three approaches, depending on the availability of grid electricity and the maturity of electricity markets.
- Electricity Storage Requirements: Each of the three types of installations are likely to have different requirements for electricity storage, which will also vary with the role of solar PV on the electricity grid (for grid –connected systems), and the types, requirements for, and timing of electricity end-uses.
- Residential Consumer Markets: Program delivery approaches will need to be tuned to the types of residential consumers, and in particular, which actors make the decisions about energy sources and residential infrastructure. It is possible that different markets could be served by different programs.

**Option Description**

[Provide a general concept description or “overview” of the technology/policy option including its purpose and the rationale behind it and generally how it will be implemented to reach goals, including local feasibility. The “purpose” can also be thought of in terms of its intended effects and will typically fall into one of two categories: technology adoption or change in practice. The “rationale” involves mapping to objectives (e.g. sustainable development, economic vision and goals, equity, others). If the option is related to existing policies in the nation/subnational area, then this should be noted. Typical length: 1-3 paragraphs. Include a general description of the implementation model and its key mechanisms (finance, law, etc.). Also indicate any key co-benefits or disbenefits, including land use change, or environmental benefits, including air quality, water quality/conservation, etc.]

Solar photovoltaic (PV) power systems for the residential sector provide carbon-free electricity for use in homes and potentially, during periods when production is in excess of household needs, for other electricity consumers. Solar PV systems use flat or, in future designs, even curved PV panels or PVs built into building materials to capture the energy and sunlight and convert it directly to electricity. Solar PV systems are practically infinitely scalable, ranging in size from a few watts to charge a mobile phone or other small device, to tens or hundreds of megawatts for utility-scale systems, though typical residential-scale systems would be in the tens of watts to hundreds of kilowatts size range. Solar PV panels can be mounted on buildings, placed on support structures built on vacant land, or incorporated into infrastructure such as parking lots, retaining walls, bridges, and other structures, wherever a relatively unobstructed southern (in the northern hemisphere) exposure is available.

Solar PV systems, because their peak output generally occurs when temperatures are warmest and power use for air conditioning, particularly in a climate like South China's, is near peak levels, can help to relieve peak power demands on both electricity supply systems and local transmission and distribution grids, depending on how the systems are configured and the locations of the projects. One recent estimate of the potential of residential solar PV power in Guangdong province suggests that installation of 13.9 GW (gigawatts, or millions of kilowatts) of capacity are possible, with annual output of 16 TWh (terawatt-hours, or billions of kilowatt-hours).[17]

There are at least three basic ways that residential solar PV systems can be configured. The first, and most common in nations where electricity grid systems are well-established, is a grid-connected configuration where PV panels either provide power directly to the grid, and the residence purchases power back from the grid to meet daily needs, or where solar PV power goes first to meet the needs of the households, and any excess is sold to the grid. In either case, the electricity grid provides power during those times when there is insufficient electricity production by the PV system to meet household needs. The second type of system is a grid-independent or "off-grid" system, where PV power is used for household needs but also charges a battery or other energy storage device, to be drawn upon when direct power from the PV system is not available or insufficient. The third type of system can be thought of as a hybrid, whereby a number of households share a PV system and share electricity/energy storage in a "micro-grid" configuration, which may be supplemented by a non-solar power source, such as a gas turbine or diesel engine-generator, and/or supplemented by some imports of grid power. In Guangdong province, in which nearly all households are connected to the energy grid, the first and third of these options are likely to be the most practical, although the off-grid option may be applicable for a minority of remote areas in South China, and is certainly applicable in many nations, including in Sri Lanka and other areas of South and Southeast Asia.

Considerations for the financing of Solar PV systems will likely focus on providing the means for **programs** to market, purchase, install, and operate PV system **projects**. The **projects** themselves may be at the individual household, building, or neighborhood level, thus tens, hundreds, or many thousands of individual projects may be included in a given **program**, which would likely be targeted to one or more types of markets for residential solar PV in a given geographic area. Differentiation of markets could be by building type, rental or owner-occupied units, and existing or new residences, as well as by area and/or electricity provider, as well as by the households' income levels.[18] Potential sources of finance

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[17] Gang He and Daniel M. Kammen (2016), "Where, when and how much solar is available? A provincial-scale solar resource assessment for China", *Renewable Energy,* Volume 85, page 74-82, available as https://rael.berkeley.edu/wp-content/uploads/2015/08/He-and-Kammen-Solar-Resource-for-China-2015.pdf.

[18] Attracting capital for investments into low income communities is much more difficult than providing funds for investments by wealthier homeowners, and capital for investment into low-income communities comes with a much higher cost of capital (expressed in the form of a higher interest rate), since credit defaults are expected to be much higher and the job security of residents (which affects the rate of default) is likely much lower among poorer consumers. Government financial involvement and credit enhancements are thus much more important for attracting private capital into low income programs.

range from private household funds (equity), to private bank financing (household debt), developer financing supplemented by enabling mechanisms, such as utility or government rebates, and/or funds from carbon trading systems. Combinations of these types of financing are possible and likely for various types of programs. Both program implementation and financing could be multi-layered, with a local or regional group coordinating the implementation of a program in a local area, but working under a regional or national agency. Similarly, local lenders could bundle loans for solar PV systems for financing by a larger agency, which in turn might get some of its financing from a multilateral bank (for example).

*In the specific example shown here, we focus on an ongoing program based in Bangladesh. The Solar Home System (SHS) program has been designed to create a market for renewable energy in off-grid areas through supplier and end-user credits along with technical and promotional supports. The program aims at fulfilling basic electricity requirements of the off-grid rural people of Bangladesh, as well as working toward achieving the Government's vision of ensuring access to electricity for all citizens of Bangladesh by 2021. A combination of individual household solar PV systems, as well as "mini-grid" systems serving rural villages and towns in Bangladesh, are being deployed.*

*The program is led by the Infrastructure Development Company Limited (IDCOL), a government-owned, independently operated, non-bank financial institution that funds infrastructure projects and off-grid renewable energy. The Government of Bangladesh receives funding from international donors (the World Bank, ADB, USAID, KfW, Islamic Development Bank, and others) and provides them to IDCOL in the form of grants and soft loans. IDCOL then channels this funding as well as necessary technical assistance to the Partner Organizations (PO) in the form of grants and soft loans. The POs are implementing the program, they can be NGOs or private companies, and are responsible for selecting the project area and potential customers, extending loans, installing solar systems, training customers, and providing after-sales services.*

## Option Design and Implementation

[This section outlines the "what you do and how you do it" aspects of the option with a series of breakdowns.]

### Goals

[Specific, clearly defined, numeric metrics that address goals and objectives of the option, with explanation as needed. Goals should be expressed in units appropriate to the policy and its objectives, i.e., % of market penetration and access to technology, number of installations, quantity produced, acres affected, jobs created, risks avoided, etc. These should be achieved over and above existing and planned (business as usual or BAU levels).]

- *IDCOL has a target of financing 6 million SHS by 2021 with a total estimated generation capacity of 220 MW of electricity, or an average of 37 watts per system. By the end of 2016, around 4.1 million SHSs had been installed under the program, in remote rural areas of Bangladesh, and these are providing clean electricity to an estimated 18 million people. Recent results of the program suggest that the capacity per system has been increasing, so the overall MW target may ultimately increase.*

- *IDCOL targeting the implementation of 50 mini-grid systems by 2018. Based on available information, 18 of these projects have been approved, and seven are operational, serving 5000 rural households.*[19]

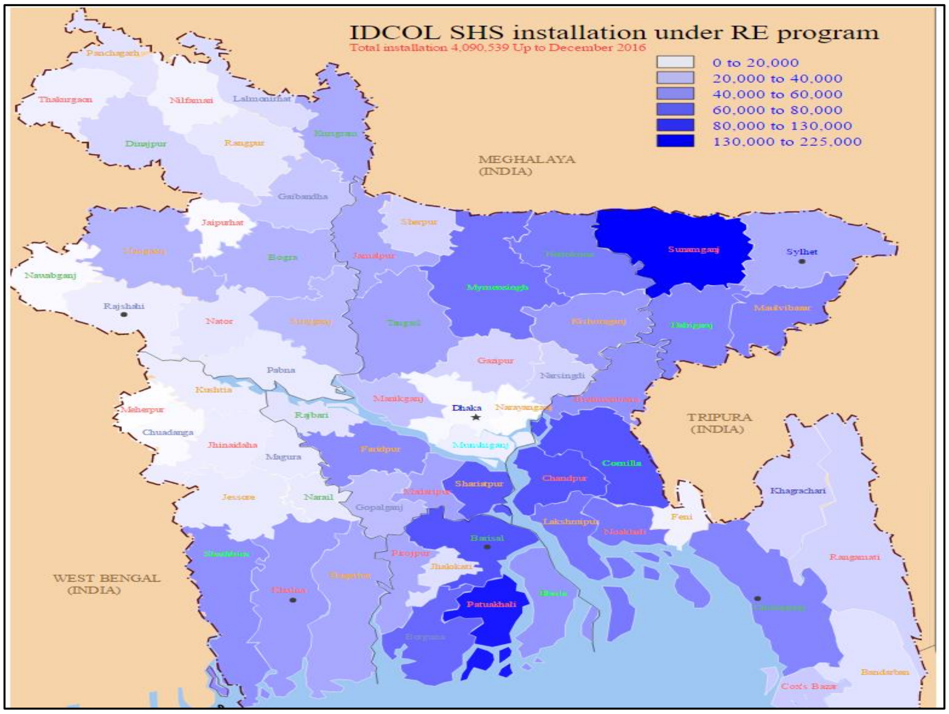
**Location**

[Identify specific geographic location and scale.]

*The SHS Program focuses on remote rural areas of Bangladesh that are currently without grid electricity, focusing on locations in the southern, eastern and northeastern provinces of the country. Currently, the highest numbers of installations under the program are in Sunamganj and Patuakhali provinces.*

*The map in Figure 1 shows solar PV installations under the program as of December 2016.*

**Figure 1: Solar PV Installation Map (as of December 2016)**




**Timing**

[Identify start, ramp up, completion, and other any important timing requirements, assumptions or concerns.]

*The SHS program was started by IDCOL in 2003, and the World Bank portion of funding was approved in late 2007.*[20] *By mid-2014, 3 million individual systems had been implemented.*[21] *Figure 2 shows the ramp-*

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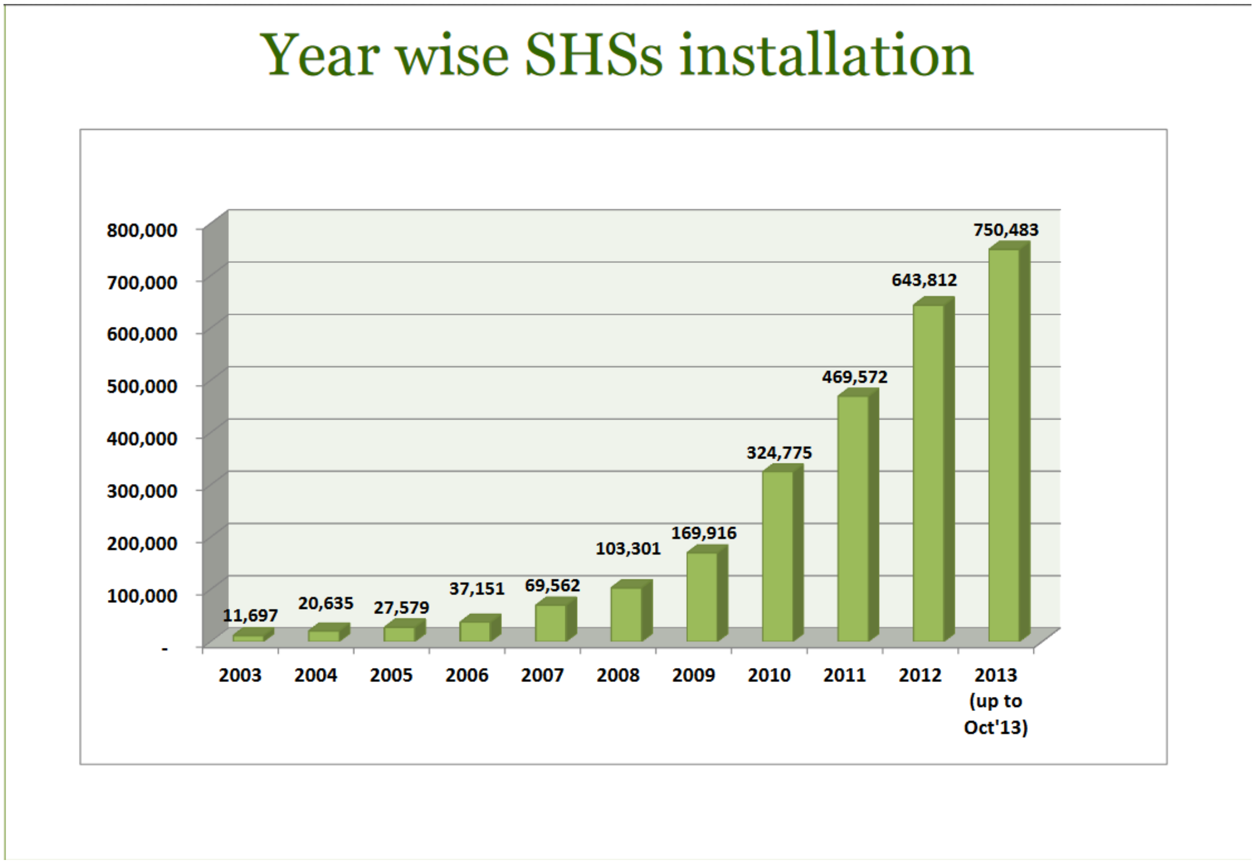
[19] See http://idcol.org/home/solar_min.
[20] See http://idcol.org/home/solar and http://projects.worldbank.org/P107906/bangladesh-idcol-solar-home-systems-project?lang=en.
[21] See http://www.worldbank.org/en/news/press-release/2014/06/30/bangladesh-receives-usd-78-million-to-install-an-additional-480000-solar-home-systems.

*up of installations over time from 2003 through 2013, indicating the increase in installations in the first 6 or so years of the program during the organization and funding phase, followed by installations at a more rapid pace once the program became established.*[22]

**Figure 2: Ramp-up of Solar PV Installations under SHS Program (as of October 2013)**




**Other**

[Use this to indicate any pertinent option design features or issues not covered above. These could be exemptions or thresholds which include or exclude involved entities.]

For residential solar PV programs in South China, or in many other jurisdictions in Asia, a separate program, or a separate part of a main program, may need to be developed to provide solar PV hardware, financing, and delivery packages suitable for low-income households and/or government-run housing, including for low-income residents and, for example, for government employees.

**Implementation Model**

[Summary description of the overall process by which the option is moved from startup to final implementation, including a diagram that shows each of the steps and the parties involved and

[22] From Nazmul Haque, "DCOL Solar Home System Program", dated December 2013, and available as https://sustainabledevelopment.un.org/content/documents/4923haque.pdf.

requirements needed for each stage of decisions, including metrics in a table with supporting narrative on stepwise procedures.]

*Table 1, below, offers a description of the main implementation phases for the Bangladesh Solar Home Systems Program with respect to the parties involved, implementation mechanisms used, and analytical methods that would be required to support the development, implementation, and evaluation of the program. In some cases, we have inferred some of the information in the table below based on our understanding of the SHS program.*

**Table 1: Implementation Model for Bangladesh Solar Home Systems Program**

| Steps | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Phase Name** | Develop and implement supporting mechanisms and gather information for program planning and evaluation | Multilateral agencies and other entities provide source funding for the program (grants and soft loans) | Government of Bangladesh (GOB) receives the source funds and sets up a special purpose entity (IDCOL) to administer and implement the program | IDCOL and partners perform detailed program design and development, including putting in place administrative systems | IDCOL Identifies Partner Organizations (POs) to administer financing mechanisms, marketing, customer acquisition, identify equipment suppliers, and provide management. IDCOL provide training and support and monitors the implementation of the program. |
| **Parties Involved** | • Technical and program experts from multilateral agencies, the Government of Bangladesh, and NGOs (some may be consultants)<br>• Market survey contractors<br>• Renewable resource assessment contractors | • World Bank<br>• European Bank for Reconstruction and Development<br>• US Agency for International Development (USAID) | • Government of Bangladesh<br>• Special Purpose Entity (IDCOL)<br>• Credit Rating Agency of Bangladesh (CRAB) | • Government of Bangladesh (including ministries and agencies involved)<br>• IDCOL<br>• Technical, program, and financing experts, and other planners | • IDCOL<br>• Partner Organizations (POs)<br>• Qualified Equipment Suppliers/Vendors<br>• Phone marketing organizations |

| Steps | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Legal, Policy, Administrative, and Financial Mechanisms** | **Financing and Legal Mechanisms:**<br>• Multilateral agencies or others provide funding for initial design and assessment work.<br>• Government and funding agencies work together with experts to develop program concept, prepare estimates of costs for the program and plans for implementation, secure funds from donors | **Financing and Legal Mechanisms:**<br>• Government and funding agencies work together to further revise program concept, prepare estimates of costs for the program and plans for implementation, secure funds from donors<br>• Government signs contracts with funding agencies<br>• Funding agencies provide technical assistance needed | **Administrative Mechanisms:**<br>• Design and prepare legal documentation for the special purpose entity (IDCOL)<br>**Financing and Legal Mechanisms:**<br>• Transfer funds to IDCOL, hire employees, and further develop implementation plans<br>• Perform credit rating on IDCOL by the state rating agency (CRAB)<br>• Develop procedures for operating national loan revolving fund<br>• Set procedures for quality control.<br>• Establish technical training requirements and programs for PO managers and employees<br>• Provide soft loans and buy-down grants to POs (amounts falling over time)<br>Create bundles of loans for reinvestment by private and public institutions | **Financing and Legal Mechanisms:**<br>• Government and/or multilateral agencies or others provide financing and/or technical support for detailed program design<br>• Set up overall administrative procedures, including communications protocols<br>• Identify other national or jurisdiction-level programs with which the SHS program might interact | **Administrative Requirements:**<br>• Technical Specification and Certification Requirements for SHS systems, installers<br>• Solicit applications for POs by jurisdiction<br>• Assess readiness and Effectiveness of POs, and select/certify operators for specific areas<br>• SHS Systems Selected by POs Quality Check<br>**Legal Requirements:**<br>• Environment Conservation Act 1995<br>• Environment Risk Management (ERM) Guideline of Bangladesh<br>• Evaluate the level of interference of local political officials into the program implementation.<br>**Financial Mechanisms:**<br>• Create bundles of loans for reinvestment by private and public institutions<br>**Policy Requirements:**<br>Evaluate the extent of healthy, or unhealthy, competition between the POs induced by the program |

| Steps | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Analytical Requirements** | **Supply/Demand**<br>• Review of fraction of homes lacking electricity nationally<br>• Review baseline expectations for need for energy services, including growth in electricity demand and in electrical grid interconnections<br>• Identify availability of solar technology and suitability for application for SHS | **Supply/Demand**<br>• Revise estimate of overall markets for program<br>• Estimate capital requirements for program based on scale desired and technologies to be included<br>• Estimate market response to program<br>• Assess funding available, and adjust scale as needed | **Credit Rating Indicators:**<br>• Capital on hand versus amount of loans outstanding in revolving fund.<br>• Fraction of loan defaults<br>**Supply/Demand**<br>• Assess market: Number of households in each area that are candidates for program based on lack of access to grid electricity, both current and future<br>• Assess market: types of consumers/households and shifts over time (household size, dwelling type, household versus village scale systems)<br>• Assess market:—estimate typical power and electrical energy requirements by household and by end-use—current and future (including trends in type/number/efficiency of devices used)<br>• Follow trends in technology, including PV and battery technologies, costs, performance, availability | **Supply/Demand/Financial**<br>• Identify administrative costs for program<br>• Identify initial system cost and related parameters of program, including costs of alternative fuels, so as to be able to design size and interest rates of loans offered under program | **Project Risk Assessment Indicators**<br>• Environmental Risk – vulnerability of selected systems as installed to windstorm, flood<br>• Technical Risk – Failure rates of installed systems, requirements for repairs<br>**POs Effectiveness Indicators:**<br>• Number of employees<br>• Number of years of education by employee<br>• Experience and expertise of employees<br>• Debt/equity ratio of POs<br>• Number of systems placed per employee, per application received<br>• Fraction of performing/non-performing loans on time and with grace period<br>• Number of complaints about installations<br>• Successful rate of repayment during the extended grace period in the past, and during the program implementation Rate of product voluntary return by customers due to the perception that cost does not justify the benefit |
| **Other Requirements** | If/as needed | | | | |

**Table 1: Implementation Model for Bangladesh Solar Home Systems Program (continued)**

| Steps | 6 | 7 | 8 | 9 |
|---|---|---|---|---|
| **Phase Name** | POs identify customers (market segments), arrange for installation of solar home systems (SHSs) and provide after-sale services. PO also performs market analysis for prediction of the future trends in program adoption | Suppliers identified by POs install SHSs. POs, SHS suppliers or other companies provide phone support to customers. Program evaluation is carried out for POs and/or IDCOL by hired evaluation service providers | Households repay their loans in fixed monthly payments to POs. Households assume the ownership of the system | Based on Program Evaluation, program is scaled up to other jurisdictions in Bangladesh, and potentially to other customer segments |
| **Parties Involved** | • Partner Organizations (POs)<br>• Qualified Equipment Suppliers/Vendors<br>• Customers in Different Customer Segments | • Partner Organizations (POs)<br>• Qualified Equipment Suppliers/Vendors<br>• Customers in Different Customer Segments<br>• Phone support service providers<br>• Evaluation services providers | • Different Customer Segments: Individual households using systems of different sizes<br>• Village-level consumers or village cooperatives<br>• POs | • IDCOL<br>• POs<br>• Qualified Equipment Suppliers/Vendors<br>• Customers in Different Customer Segments |

| Steps | 6 | 7 | 8 | 9 |
|---|---|---|---|---|
| **Legal, Policy, Administrative, and Financial Mechanisms** | **Financing and Legal Mechanisms:**<br>• Structuring and standardizing soft loan contracts and micro-credit services<br>• Evaluate the rate of return (interest rate) on loans<br>• Evaluate the failure rate of loans | **Administrative Requirements:**<br>• Technical Specification and Certification Requirements for SHS systems, installers<br>• Define installer procedures and protocols, including protocols for customer contact and handling complaints<br>• Develop information to be provided by suppliers to customers<br>• Develop contracts between suppliers and POs<br>• Develop contracts to be provided by suppliers to customers<br>• Assess readiness and Effectiveness of POs, and select/certify operators for specific areas<br>• Quality Check requirements for installed SHS Systems | **Legal Mechanisms:**<br>• Contract signed with PO obligating repayment of loan, specifying consequences if loan is not repaid<br>**Financing Mechanisms:**<br>• Personal household funds, including savings from avoided fuel use used to make monthly payments<br>**Administrative Requirements:**<br>• Householder provides basic maintenance on system | **Legal, Policy, Administrative, and Financial Mechanisms**<br>• Expand mechanisms adopted for initial jurisdictions as needed to scale up to additional jurisdictions<br>• Study any differences in legal requirements or other local differences between jurisdictions, and account for differences in program planning |
| **Analytical Requirements** | **Ex-ante Demand and Loan Performance Analysis**<br>**Methods:**<br>• Contingent valuation (CV) method, probit regression analysis, price elasticity of demand estimates from probit model<br>• Survey questionnaire (for CV) | **Assessment of program results (largely qualitative surveys)**<br>• Evaluation of customer satisfaction with delivery of systems and services under program<br>• Evaluation of contractors providing services | • Total price of the specific solar product offered ($)<br>• Loan terms for monthly installments ($/month, Interest rate -%), | • Expanded versions of requirements for programs in selected jurisdictions |

| Steps | 6 | 7 | 8 | 9 |
|---|---|---|---|---|
| | • Standard credit quality evaluation procedures adopted from commercial banks<br>• SHS Social Value Assessment<br>**Metrics:**<br>• Adoption rate of households<br>• Adoption patterns by sex, age, education of household heads<br>• Adoption pattern by income, level of debt among the adopter households, statistical relationships between the price of the product and household economic factors, energy consumption among adopters and non-adopters<br>• Customer Credit Quality Evaluation<br>• Rate of product voluntary return by customers due to the perception that cost does not justify the benefit | • Surveys to assess how customers have adapted their lifestyles and (qualitative) as a result of receiving program products and services (for example, more use of lighting for education or productive activities<br>**Quantitative Assessments of Program Results**<br>• Surveys to assess failure rates of equipment (panels, mounts, batteries, lighting)<br>• Surveys to assess how many hours per day power from systems are being used<br>• Surveys to assess what fuels are being displaced by SHS systems, and in what quantities per day or month<br>**Metrics:**<br>• Failure rate of equipment<br>• Rate of customer satisfaction<br>• Estimates of average daily use of SHS<br>• Estimates of average fuel use displaced by SHS | | |
| **Other Requirements** | If/as needed | | | |

**Planning and Implementation Steps**

[Expand the discussion of each Step outlined in the Implementation Model above. In Step 1, identify the initial formative planning requirements needed to support initiation of implementation in subsequent steps of the model. In the final step, describe what is needed to monitor success of the program/project and to scale-up implementation of similar programs/projects to the jurisdictional scale]

*Please see Table 1 for an overview of the planning procedures used in the Bangladesh SHS program. The steps in the planning process are as listed below.*

> **Step 1:** *Develop and implement supporting mechanisms and gather information for program planning and evaluation.*
>
> **Step 2:** *Multilateral agencies and other entities provide source funding for the program (grants and soft loans).*
>
> **Step 3:** *Government of Bangladesh (GOB) receives the source funds and sets up a special purpose entity (IDCOL) to administer and implement the program.*
>
> **Step 4:** *IDCOL and partners perform detailed program design and development, including putting in place administrative systems.*
>
> **Step 5:** *IDCOL Identifies Partner Organizations (POs) to administer financing mechanisms, marketing, customer acquisition, identify equipment suppliers, and provide management. IDCOL provide training and support and monitors the implementation of the program.*
>
> **Step 6:** *POs identify customers (market segments), arrange for installation of solar home systems (SHSs) and provide after-sale services. PO also performs market analysis for prediction of the future trends in program adoption.*
>
> **Step 7:** *Suppliers identified by POs install SHSs. POs, SHS suppliers or other companies provide phone support to customers. Program evaluation is carried out for POs and/or IDCOL by hired evaluation service providers.*
>
> **Step 8:** *Households repay their loans in fixed monthly payments to POs. Households assume the ownership of the system.*
>
> **Step 9:** *Based on Program Evaluation, program is scaled up to other jurisdictions in Bangladesh, and potentially to other customer segments.*

**Parties Involved**

[Identify those affected by outcomes of the option and those involved in its implementation and their roles, including involvement in the planning and implementation steps above.]

*Major parties involved in the Bangladesh SHS program include the following:*

- *International donors*
- *Government of Bangladesh*
- *IDCOL*
- *NGOs*
- *Private Companies providing goods and services to support program, such as system components and installation, product support, quality control evaluation; and/or providers of alternative products, such as lighting fuels*

- *Suppliers of solar PV panels and batteries*
- *Homeowners and family members participating in/benefiting from program*
- *Educators/training providers*

In other applications of solar PV systems in more urban-dominated settings, such as in South China, additional parties directly affected by a Residential Solar PV Program might be expected to include:

- Residents of different types of buildings, who will act as hosts to solar PV systems, and will see their electricity bills decline as a result of using the solar PV power and/or selling power to the power grid. Residents will likely also incur some costs to participate in the program, such as upfront payments for loans, an environmental benefit charge on the electricity bills, or other outlays.

- Utility generation and distribution companies providing electricity service, who will see conventional (likely coal-fired) power and the costs thereof displaced by PV power, may obtain benefits in terms of peak power demand reduction and reduction in the need for new transmission and/or distribution systems, and will face costs associated with buying PV power, updating infrastructure to accommodate purchase of PV power (for example, smart meters and grids), and, possibly, with providing back-up power, electricity storage, and other ancillary services once PV power constitutes a significant portion of the energy on the grid.[23]

- Suppliers of fuel to central power stations, including coal and/or natural gas suppliers, will see reduced sales as a result of the implementation of a residential solar PV program though some or all of these suppliers may be outside the program jurisdiction, or even outside of the province or country.

Similar to the Bangladesh SHS program, parties involved primarily in implementing a Residential Solar PV Program in a location where grid-based power is widely available will likely include the following (some of these parties will arguably also be affected directly or indirectly by the program, though their use or provision of energy will not be affected):

- Solar PV panel and mounting producers, vendors, and installers.

- Private institutions, potentially including banks, for-profit lenders, and non-profit groups, providing financing for solar PV systems.

[23] At some point, perhaps in the not-too-distant future, a key grid benefit of distributed solar PV programs may be the aggregation and optimization of a large number of PV and energy storage units connected to the grid, allowing the reduction of overall electricity costs, reduced peak demand, and other benefits. This arrangement corresponds to the "virtual power plant" concept that is being tested in programs in the United States, for example, in New York City, where Consolidated Edison will administer a virtual power plant and coordinates hundreds of PV + lithium ion storage assets located on the premises of residents. See, for example SunPower (2016), "Con Edison "Virtual Power Plant" Program Combines Solar and Storage to Improve Grid Resiliency ", available as http://newsroom.sunpower.com/2016-06-13-Con-Edison-Virtual-Power-Plant-Program-Combines-Solar-and-Storage-to-Improve-Grid-Resiliency.

- Organizations, potentially including government agencies, institutes, and non-profit or for-profit firms, administering the solar PV program.
- Representatives of government agencies that might provide partial funding for the program.
- Bilateral or multilateral donors providing grant or loan financing for the program.
- Representatives of provincial carbon trading authorities that might provide partial program financing.

Parties benefiting or facing costs indirectly from a Residential Solar PV Program involving grid interconnections will include the ratepayers of the utility affected by the program, whose utility bills may go up or down, relative to business as usual, as a result of the program, the taxpayers of the region, if government funds are used to support the program, citizens of the region, to the extent that air pollution and other local and regional environmental problems decrease as a result of solar PV deployment, and the citizen and biota of the world, to the extent that the program contributes to a reduction in the impacts of climate change.

**Implementation Mechanisms**

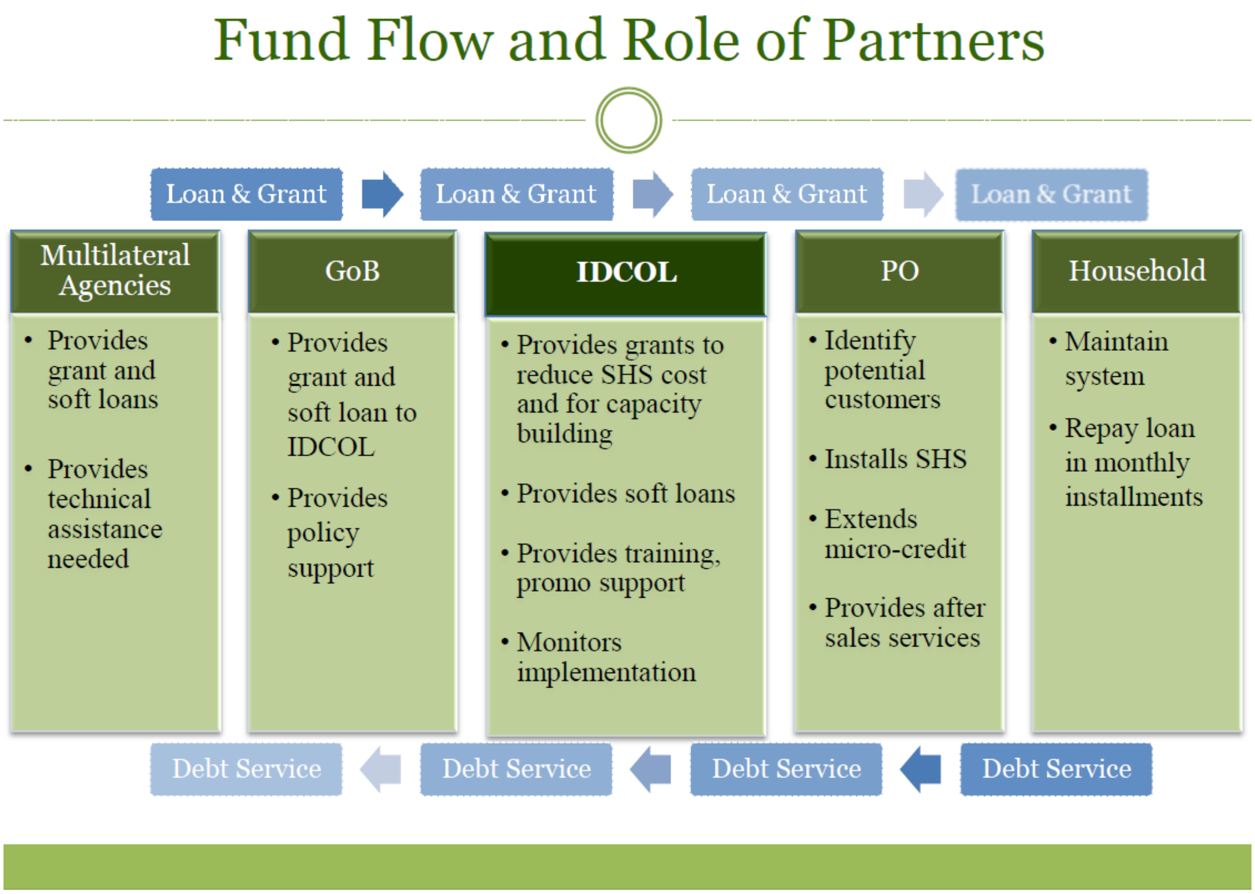
[From the planning and implementation steps identified above, provide further detail on the specific legal, administrative, and financial mechanisms needed for implementation.

- Legal
- Policy
- Administrative
- Financial]

*Please see Table 1 for an overview of the implementation mechanisms used in the Bangladesh SHS program. Figure 3 provides an overview of the way that the major parties in the program interact with regard to the flows of funds in the program.*[24]

[24] From Nazmul Haque, “DCOL Solar Home System Program“, dated December 2013, and available as https://sustainabledevelopment.un.org/content/documents/4923haque.pdf.

**Figure 3: Financial Mapping Chart**




*One element described in some detail in project documents is the procedure for "Ex-ante" Demand Analysis in Bangladesh SHS Program. As deployment of the Bangladesh SHS program continued, it was necessary to collect empirical data for the subsequent demand analysis steps in order to know how to modify the program to improve market penetration and financial performance. To collect and evaluate data on the SHS program, a large survey with pre-designed questionnaire was commissioned. The survey covered 4000 rural households in different provinces, out of which 1600 are the households that adopted the solar home systems (SHS), 400 are those that did not purchase the product but where reached by the program, and the remaining 2000 are households located in the villages not covered by the program (no operating POs exist yet). The questionnaire included questions designed to assess the most significant drivers and factors of purchasing solar PV product purchasing decisions. The most significant drivers of demand identified through the survey were: household income, number of students in the household (a measure of need for education), need for entertainment, need for higher quality light, and the price of the SHS product. Some of the detailed outputs of the survey, and the equations used to derive them, are described in the Annex to this Policy Implementation Document.*

## Baseline Conditions

[This should also capture the relevant elements of any existing and/or planned actions at the subnational/national level that affect implementation of the option. Measures are designed to be incremental to existing and planned actions (baselines). Include a description of any existing program and the relationship to the option (for example, applicable emissions offsets, funding source). In addition to BAU existing/planned actions, also summarize the BAU management of the resource (if any). This would include BAU land use that would be affected by implementation of the option (e.g. conversion of forest or cropland to land used for growing energy crops)]

*In the rural areas of Bangladesh targeted by the SHS program, grid electricity is typically not available, or is available very intermittently. As a consequence where electricity is used, for example in portable radios, flashlights, or other electronics, batteries are the typical source of power, and typically at very high cost per delivered kilowatt-hour. Light is often provided by lamps fueled with kerosene or other oil products, or by use of candles or oils from oilseeds. Combustion of these fuels adds to household expenses, and contributes to indoor air pollution. The light provided by oil lamps is also often inferior to that provided by electric lamps. Lack of light often limits opportunities for after-dark productive activities, education, and other household activities.*

## Metrics for Implementation Assessment

[Create a general equation followed by the procedure by which it will be customized to the technology/policy measure at broad as well as specific level through use of methods and metrics.]

### Energy and RE Technology Demand

1. Key Issues

   [Describe the key issues that need to be addressed. This section addresses both energy demand as well as the market demand for the RE Technology. Reference should be made to the jurisdictional (provincial or municipal) baseline for energy demand to frame the needs for new generation at that scale (e.g. new GW of capacity needed in five-year increments through 2050). The local energy demand method is described below.

   Estimations of market demand for each RE Technology will be different as a result of the different players in each market. The market for a distributed generation program such as a residential solar PV program option consists of solar PV project developers (sellers) and residential households (buyers). The market for a dedicated RE power plant (e.g. biomass, large scale wind) consists of RE project developers (sellers) and the electricity authority (buyer). Therefore, the methodology for estimating market potential for distributed RE programs versus dedicated RE plants will need to be formulated accordingly]

*Based on national baseline reports and other sources,*[25] *Bangladesh's electricity demand in 2014 was about 34 TWh in 2016, or about 214 kWh per capita, one of the lowest rates in the world*[26]*. Broken down by end use, the "domestic" sector demanded over 50% of electricity (and rising) in 2015, with, and the industrial sector about 33% (and falling), although an alternative source document suggests slightly different figures—about 42-47 TWh total in 2013, and 54 TWh in 2015, with the residential sector accounting for about 33% in 2013, the industrial sector about 57%, and the commercial/public and agricultural sectors each about 5 percent.*[27] *Under BAU conditions, electricity demand is expected to grow by nearly a factor of three between 2016 and 2030,*[28] *which would imply demand on the order of 230 TWh by 2035. By that year, we assume that the residential sector consumes 40% of the total electricity requirements, the commercial/institutional sector 10%, and the industrial sector 45%.*[29]

2. Methodology: Local Energy Demand

[Include general methods and metrics for the option.]

*For the Bangladesh SHS program, as the focus is on providing solar home systems for rural households currently without access to electricity, methods for evaluating local energy demand will likely include:*

- *Determine the number of non-grid connected households in the rural area where the program is to be deployed.*
- *Collect socio-economic data such as household size (persons), typical dwelling size (square meter) and number of rooms, ages of household members, income, and other data.*
- *Assess end-uses and devices currently used in households, including lighting, cooking, entertainment, tools use, and others, including end-uses supplied with batteries or solid or liquid fuels, but focusing on end-uses for which electricity is or is likely to be used.*
- *Assess potential electricity end-uses once a SHS is deployed, probably by reference to data from households of similar socio-economic characteristics that are already using SHS technologies.*

[25] See, for example, UNDP and Bangladesh Ministry of Energy (2011), *UNDP Global Project: Capacity Development for Policy Makers to Address Climate Change*, available as http://www.undpcc.org/docs/Investment%20and%20Financial%20flows/I&FF%20reports%20and%20suppl%20information/Bangladesh/Bangladesh_Assessment_Energy_11_01_for%20upload.pdf.

[26] See, for example, Saiful Islam and Md. Ziaur Rahman Khan, "A review of energy sector of Bangladesh", dated December 2016, and available as http://ac.els-cdn.com/S1876610217302230/1-s2.0-S1876610217302230-main.pdf?_tid=70a8d930-4b12-11e7-9238-00000aab0f6c&acdnat=1496793003_c3cb2e9be4572765540b6656819eeb3d

[27] See People's Republic of Bangladesh Ministry of Power, Energy and Mineral Resources and Bangladesh Power Development Board, *People's Republic of Bangladesh Survey on Power System Master Plan*, 2016, available as http://powerdivision.portal.gov.bd/sites/default/files/files/powerdivision.portal.gov.bd/page/4f81bf4d_1180_4c53_b27c_8fa0eb11e2c1/1%20%281%29.pdf; and Institute for Energy Economics and Financial analysis, *Bangladesh Electricity Transition, A Diverse, Secure, and Deflationary Way Forward*, dated November, 2016.

[28] See export.gov, "Bangladesh - Power & Energy", available as https://www.export.gov/article?id=Bangladesh-Power-and-energy.

[29] No projections for electricity demand by sector in Bangladesh were immediately available, thus our assumptions are shown for this example.

- *Estimate the growth in the number of households and other parameters, and calculate future demand for the energy services that a SHS would provide power for.*

*Note that since the program provides electricity to households that currently have no access to electricity, the energy and emissions impacts may not be accounted for in the current national baseline (i.e. unless these households were expected to gain access to power during the forecast period).*

More generally, for Residential solar PV programs, it will, in cases where households without grid power make up a large fraction of consumers, be necessary to estimate energy demand for the entire residential sector (those with and currently without access to power) to understand the total energy demand that could be offset with PV systems. The following, however, provides a method for demand estimation that focuses on electricity:

a. Begin with location-specific historical consumption for each end use sector from the relevant electricity authority:

    i. $R_d$, - Residential energy demand for the historical base year (MWh). Note: further disaggregation to subsectors is also highly valuable if available (e.g. rural vs. urban residential; commercial vs. institutional; disaggregation for key electricity consumption subsectors)

    ii. For forecasting methods development, consider the provincial-level forecasting methods from the LCD Toolkit as a starting point for further refinement. These are in 2 separate memos located on iMC[30]: one for the residential, commercial and institutional sectors; the other for the industrial sector. Higher levels of sophistication could be added to these forecasting methods to address expected changes in climate (leading to greater demands for heating or cooling); and energy price effects (e.g. elasticity of demand to future prices in electricity).

b. Include equations for estimating local electricity demand by sector and additional details of end use. As a generic example:

    i. Electricity Load Growth = ƒ (population, income growth, climate changes, technology innovation, price elasticity)

    ii. Allocation of sector-based load to energy end use: % heating/cooling, lighting, cooking, water heating, remaining plug load.

    iii. Diurnal profile summaries of sector-based load by season for key target years.

3. <u>Key Metrics: Local Energy Demand</u>

[Include specific metrics for the option, including data sources, methods, key assumptions.]

a. Electricity and direct fuels price forecasts

b. Elasticity of energy demand by end use sector

[30] https://ccs.imeetcentral.com/ssouthchinare2/folder/WzIwLDkwMTk5Mjhd.

c. End use technology mix and shifts (possibly, as a function of income): lights, fans, A/C, refrigeration, appliances, equipment

d. Population, economic and income status and growth (rural versus urban breakdowns)

e. Climate change effects on heating and cooling demand

f. Breakdown of sector demand by end use (lighting, heating, cooling, appliances, other) and technology innovation rate impacts on consumption by end use

g. Sector and total electricity demand diurnal load profiles (by season for key target years)

h. Policy incentives

  i. Caps: stringency, baseline GHG intensity, flexibility, value of allowances

  ii. Other policies and requirements if/as needed

**Energy Supply**

1. Key Issues

   [Describe the key issues that need to be addressed. Summarize the jurisdictional energy supply baseline, including what new generation sources are expected to be put in place in the future under business as usual (BAU) conditions to meet future load growth. Also, how will the RE option being considered impact the BAU generation system (e.g. if it is tied to the grid or not, if it ties to a grid that serves the entire jurisdiction or to a smaller independent grid)?

   The remaining sections address the RE technology for this option.]

   *Historically, electricity supply in Bangladesh has been dominated by gas and oil-fired thermal power plants, though recent additions to the grid have been and are projected to be coal-fired. In 2015, our rough estimate of the carbon intensity of power supply was 650 kg $CO_2e$/MWh (including T&D losses). Under BAU conditions, with the projected large increases of coal-fired power in Bangladesh, the average carbon intensity of power supply may rise to 800 kg $CO_2e$/MWh by 2035, and the marginal carbon intensity (based on coal-fired power) may be over 900 kg $CO_2e$/MWh.[31]*

   *The main "baseline" alternatives to local SHS systems that involves electrification would likely be to extend the national grid, at significant cost and likely with large transmission and distribution losses, to the small villages served by the SHS program, or to install diesel generating units in rural centers. Making this assumption, calculating the impact of the program at the provincial level, and by aggregation, the national level, will require an estimate of the solar PV generation by year, estimates of the emissions from coal-fired and diesel-fueled power plants per unit of generation, and estimates of line losses (currently about 11.6 percent in Bangladesh overall, but likely to be much higher in rural areas). Alternatively, if electrification over the course of the*

[31] Rough estimates by CCS team. Typically, these data are available for any given grid based on a combination of historical statistics about power plant operations and efficiencies, and on information about power generation capacity expansion capacity by type of generator, including the types of fuels used and efficiencies of the different power plant types. Note that for the calculation of avoided emissions, it is typically necessary to estimate which types of power plants are "on the margin", that is, will be run less (or avoided entirely) as solar PV capacity and electricity output is increased.

*timeline of the program seems unlikely, an estimate could be made of the avoided GHG emissions from, for example, fuel-based lighting sources, although it is likely that SHS systems will provide significantly greater energy services than the fuel-based lighting systems that they replace, thus the comparison between the two would be incomplete.*

2. Methodology: Local RE Supply

   a. *Local Resource Assessment*

      i. *Provincial measures of insolation (annual, daily, and monthly) per unit area.*

      ii. *Assessment of area of unshaded roof for the average household available for mounting PV systems, though this is unlikely to be a constraint for smaller PV systems like those included in the Bangladesh SHS program.* Note that in applications, such as some of those likely in South China, where PV installations will not be on rooftops, on the sides of buildings, or on other developed hardscapes (such as parking lots), some sort of land-use impact may need to be factored in, which may result in changes to biomass and/or soil carbon inventories on the areas used for PV panels.

      iii. *Number of households/dwellings in the program target area.*

      iv. *Fraction of households that are not candidates for SHS systems.*

      v. *Average system efficiency, including battery charging, of SHS systems likely to be deployed.*

      vi. *Fraction of electricity produced that is actually used.*

   b. Supply Technology Considerations:

      i. *Renewable power production: The general equation for renewable power production from solar PV for a program like the SHS is:*

$$RP = PC \times C_f \times UF \times 8760$$

*where:*
*RP = Renewable power production (MWh/yr)*
*PC = Plant capacity (gross MW of SHS deployed)*
*$C_f$ = Plant capacity factor (unitless; account for down-time by the plant for maintenance, but mainly for kWh output per unit of capacity, for example, 2000 kWh/kW-yr, which would yield a value of $C_f$ of 0.23, or 23%)*
*UF = Average fraction of electricity produced that is actually used by households, (unitless; fraction of gross output used on-site for end-uses, including battery charging/discharging losses)*
*8760 = hours per year*

      ii. *GHG emissions: Solar PV generation produces no GHG emissions.*

      iii. *PV system plant capital and operating costs:*

         1. *Generation characteristics: total MW of SHS PV capacity deployed.*

2. *Installation costs (typically, for solar PV systems, 20 to 50 percent of the overall cost of the system, but can be estimated based on available documentation).*

3. *Operation & maintenance (O&M) costs: not provide in available documentation, but typically relatively small for solar PV systems*

iv. *PV system lifetime: typically 15 to 25 years.*

3. Key Metrics

a. *PV system Capital Costs: USD 420 for a 50-watt system.*[32]

b. *Operations & Maintenance (O&M) Costs: For generation resources in general, two types of O&M costs are often specified. One is **variable** O&M, which is denominated in, for example, USD per net MWh produced, and the other is **fixed** O&M, for which the units are, for example, USD per kW-yr (that is, annual costs per kW of capacity). For solar PV systems, it is more common to report only fixed O&M costs. For small systems in the US, one recent estimate of average fixed O&M costs is USD 20 per kW-yr.*[33] *For the small PV systems included in the Bangladesh SHS program, the fixed O&M costs above would thus equate to less than one USD per year in many cases. In the case of the SHS PV systems, the fixed O&M costs would likely include at a minimum cleaning of the PV panel and periodic (perhaps every 5 years) replacement of the system's battery, though other repair costs may also occur.*

c. *Levelized cost of electricity (LCOE): 0.63 USD/net kWh used on an undiscounted basis, and 0.39 USD/net kWh used on a discounted basis, over the life of the system, calculated based on the information above and using the formulae below. This can be compared with LCOE values for other BAU generation sources and for batteries, for example. The LCOE figures may come from the electricity provider, or can be estimated, for example, for generic coal and diesel plants, on a "proxy plant" basis. There are several formulas needed to convert the various units into the $/MWh units used to express levelized costs. These are briefly described below.*

*Initial Investment Costs (IIC)*[34]*: These costs are annualized to $/MWh units for each year of expected plant operation as per the formula below:*

$$\text{Annualized IIC} = IIC * FCF * 1000 / (8760 * C_f)$$

*where:*
*IIC = initial investment costs. These include the capital costs of land and equipment, as well as any other initial costs for planning, engineering and construction ($/kW)*
*$C_f$ = capacity factor (%)*

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[32] From Nazmul Haque, "DCOL Solar Home System Program", dated December 2013, and available as https://sustainabledevelopment.un.org/content/documents/4923haque.pdf. Note that systems of several different sizes are being installed under the SHS program.
[33] See, for example, National Renewable Energy Laboratory (NREL, 2016), "Distributed Generation Renewable Energy Estimate of Costs", updated February 2016, and available as http://www.nrel.gov/analysis/tech_lcoe_re_cost_est.html.
[34] Typically reported in units of $/kW, these costs include the total costs of construction, including land purchase, land development, permitting, interconnections, equipment, materials and all other components. Construction financing costs are also included.

*8760 = hours per year*
*FCF = fixed charge factor*[35]
*1000 = conversion from \$/kW to \$/MW*

*Fixed O&M (FOM)*[36]*: These costs can be estimated for each year of SHS operation in \$/MWh units as per the formula below:*

$$\text{Annualized fixed O\&M cost} = FOM * 1000 / (8760 * C_f)$$

*where:*
*FOM = fixed O&M (\$/kW-yr)*
$C_f$ *= capacity factor (%)*
*8760 = hours per year*
*1000 = conversion from \$/kW to \$/MW*

*Variable O&M (VOM)*[37]*: These costs should already be provided in units of \$/MWh, so no conversion is needed.*

*Discounted Costs: All of the annual costs estimated above are then discounted as follows:*

$$\text{Discounted Annual Costs} = [PV_{GEN} * DR * (1+DR)^t] / [(1 + DR)^t - 1]$$

*where:*
$PV_{GEN}$ *= present value of the sum of all generation costs*
*= annualized IIC + FOM + VOM + FC (\$/MWh in each year of the plant's lifetime)*
*DR = discount rate*

*The values in the stream of discounted annualized costs are then levelized across the lifetime of the plant:*

$$LCOE = \sum \text{Discounted Annual Costs}/PL$$

*where:*
*LCOE = levelized cost of electricity (\$/MWh)*
*PL = lifetime of the plant (years)*

*Figure 4 summarizes the inputs and outputs of the LCOE calculation. Note that the LCOE values shown in Figure 4, which follow the calculations summarized above, do not include the impacts*

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[35] This factor is calculated based on assumptions regarding the plant lifetime, the effective interest rate or discount rate used to amortize capital costs, and various other factors specific to the power industry. Expressed as a decimal, typical fixed charge factors are typically between 0.10 and 0.20, meaning that the annual cost of ownership of a power generation technology is typically between 10 and 20 percent of the capital cost. Fixed charge factors decrease with longer plant lifetimes, and increase with higher discount or interest rates.
[36] Typically reported in units of \$/kW-yr, these costs are for those that occur on an annual basis regardless of how much the plant operates. They typically include staffing, overhead, regulatory filings, and miscellaneous direct costs.
[37] Typically reported in units of \$/MWh, these costs are for those that occur on an annual basis based on how much the plant operates. They typically include costs associated with maintenance and overhauls, including repairs for forced outages, consumables such as chemicals for pollution control equipment or boiler maintenance, water use, and other environmental compliance costs.

*of inflation on fixed O&M costs, and thus are slightly lower than the LCOE included in the more detailed analysis presented below (in Table 2).*

**Figure 4:**

**Estimates of Costs and Performance for Bangladesh Solar Home Systems Program**

| | |
|---|---|
| Date Last Modified: | 6/16/2017 |

**Cost and Output Assumptions for Calculations**

| | | |
|---|---|---|
| Lifetime | 20 | years |
| Interest Rate | 10% | per year |
| Discount Rate | 10% | per year |
| Capital Cost (IIC) | $ 420.00 | |
| Capacity | 50 | W per system |
| Capacity factor (Cf) | 22.8% | estimated based on an average of |
| | 2000 | Wh/yr per W capacity |
| Fraction of PV power used (UF) | 70% | Assumption |
| Fixed O&M Cost | $ 20.00 | per kW-yr |
| Variable O&M Cost | $ - | per kWh |

**Intermediate Calculations**

| | | |
|---|---|---|
| Fixed Charge Factor (FCF) | 11.75% | |
| System output used: RP = PC x Cf x UF x 8760 | 70 | kWh/year |
| Annualized IIC = IIC * FCF * 1000 / (8760 * Cf) | $ 0.70 | per kWh |
| Annualized fixed O&M cost = FOM * 1000 / (8760 * Cf) | $ 0.014 | per kWh |
| Variable O&M Cost | $ - | per kWh |

| | | |
|---|---|---|
| **Undiscounted Levelized cost of electricity (LCOE--Sum of Annualized costs on a per kWh basis)** | **$ 0.72** | per kWh |
| **Discounted Levelized cost of electricity (LCOE--Sum of Annualized costs on a per kWh basis)** | **$ 0.31** | per kWh |

4. Project Impact: *The following at a minimum will be included in the analysis of projects for South China, and can be estimated for the Bangladesh example (and are estimated in the "Results of Assessment" section below) but have not yet been found in available Bangladesh SHS Program documentation - GHG reduction from BAU (tonnes of $CO_2$ equivalent or $tCO_2e$); renewable electricity production; contribution toward jurisdictional target(s). The following impacts, however, were reported for the Program as of October 2013:*

- *"Program Achievement: : 2.6 million SHSs till October'13*
- *Number of Beneficiaries: About 12 million people*
- *Power Generation: About 110 MW*

- *Fossil Fuel Saving: 250,000 ton/year*
- *Subsidy Saving by Govt.: USD 37 million/year*
- *Direct Job Creation: 30,000 people*
- *IDCOL Investment: About USD 550 million"*[38]

**Results of Assessment**

[This section is where the quantification results are presented and discussed. The section begins with a standard table that presents key summarized results]

*Summary estimates of overall program impacts and per-household financial flows are provided below. A description of key inputs to and methods used to derive these results are provided below these summary tables.*

**RE Energy and Emissions Assessment Results**

| Bangladesh SHS Program – Level Results[39] | | | | |
|---|---|---|---|---|
| **2021 SHS PV Generation (GWh/yr)** | **2003 - 2041 SHS PV Generation (GWh)** | **Fraction of National Projected 2021 Power Demand Met (%)** | **2021 GHG Reduction ($TgCO_2e$, or Million $tCO_2e$, per year)** | **2003 – 2041 GHG Reduction ($TgCO_2e$)** |
| 420 | TBD | 0.5% | 1.9 | 37 |
| **Potential Jurisdictional – Level Impacts will vary significantly by jurisdiction, and though they cannot be determined based on the information currently available, in theory they should scale essentially linearly with the number of systems deployed in a given jurisdiction. Note that determination of GHG reduction for this program is complicated by the fact that the solar home systems likely provide more energy services than the fuel-based lighting and disposable batteries that they displace.** | | | | |

[38] From Nazmul Haque, "DCOL Solar Home System Program", dated December 2013, and available as https://sustainabledevelopment.un.org/content/documents/4923haque.pdf.
[39] Annual program-level results are provided for 2021 because that is the reported year at which the target number of installations will be reached, though it seems likely that the program will be expanded and continued at that point. Cumulative results are projected through 2041 because that is the final year of nominal life of the PV systems included in the program, though in practice lifetimes of systems will vary. In general, the time period for analysis of renewable energy policies will be fixed based on an overall national or jurisdictional energy planning or climate action planning framework.

**RE Technology Market Assessment [FOR DISCUSSION AT PRESENT]**

| Capacity of Resource (GW) | Annual Net Generation (GWh) | Metric C | Metric D | Metric E |
|---|---|---|---|---|
| *Provincial (Local) Level* | | | | |
| TBD | TBD | | | |
| *National Scale-Up* | | | | |
| 300 | 1,800 | | | |

**Project-Level Financial Assessment**

| Project (Household) – Level Results | | | | |
|---|---|---|---|---|
| **Initial Investment Costs (US Dollars)** | **NPV of Implementation Costs[40] (US Dollars)** | **Discounted Payback (Years)** | **Internal Rate of Return (%)** | **Risk-Adjusted Return on Investment (%)** |
| 420 (of which down payment is 15%) | 380 | ~2.0 (for full system cost) | 75% | 461% |

### A. Jurisdictional and Local Energy Supply and Demand

[This section will be completed based on the results of the demand/supply assessments, financing, and trading and other ancillary policy impacts. List the relevant metrics and results, perhaps in table to simplify, and then provide a step-wise description of the process used for evaluating metrics.]

- **Direct, Indirect, and Integrative Impacts**
  - [This section is where the summary of results for energy supply and demand provided above is documented. This also is where a link or reference to more detailed analysis and results can be found. Direct results include power generation/other energy and emissions impacts. Indirect results should either be quantified or at least qualitatively cited. These include energy and emissions impacts on upstream fuel supplies. Integrative impacts include jurisdictional level generation and emissions impacts resulting from scaling the technology up to that scale]
  - *Figure 5, below, summarizes the procedure and information used to estimate the electricity output and greenhouse gas emissions reductions reported in the summary table above.*

[40] Includes cost for debt service (payments made by householder to bank) and for fixed O&M.

**Figure 5:**

**Estimation of GHG Impacts for Overall Program**

| | | | | |
|---|---|---|---|---|
| Target for number of systems installed by 2021 is | | | | |
| | 6 | million systems | | |
| Average used electricity output | 70 | kWh per system/yr | | |
| (This assumes that the average size of systems installed through 2021 is 50 W, which implies that systems larger than 50 MW will be installed to balance smaller systems.) | | | | |
| Implied total used electricity output | 420 | GWh per year in 2021 | | |
| Estimated Nationwide electricity use | 83 | TWh/yr in 2021 | | |
| Which implies that SHS under the program will provide about | | | 0.5% | |
| of national electricity demand in that year. | | | | |
| Estimated annual savings in kerosene use for lighting per system | | | 96.15 | kg |
| Estimated annual savings in overall kerosene use by 2021 under program | | | | |
| | 576,923 | tonnes per year | | |
| GHG emissions per terajoule (TJ) of kerosene | | 71.87 | tonnes $CO_2e$ | |
| (See, for example, http://www.ipcc-nggip.iges.or.jp/public/gl/guidelin/ch1wb1.pdf) | | | | |
| Energy Content of Kerosene: | 44.75 | GJ/t | | |
| GHG emissions per tonne of kerosene | | 3.22 | tonnes $CO_2e$ | |
| Implied GHG emission reduction through program in 2021 | | | 1.86 | Mt $CO_2e$/yr |
| Average lifetime of PV systems installed under program | | | 20 | years |
| Lifetime emissions reduction for systems installed | | | 37.11 | Mt $CO_2e$ |

- **Key Uncertainties**
  - [This section addresses key uncertainties and any methods for addressing them in quantification results above.]
  - *Key uncertainties in assessment of the Bangladesh SHS program include the rate at which consumers will continue to purchase solar home systems, the usage of the systems (total electricity consumed), and the amount of lighting fuel and other energy sources (such as batteries) displaced by the systems.*

- **Feasibility Issues**
  - [This section addresses key feasibility issues identified and addressed or not addressed in the assessment and their implications.]

### B. RE Technology Demand

[Summarize the results of the RE technology market assessment summarized in the table at the beginning of this section.]

*The following factors are important to understanding market potential for SHS generation in Bangladesh: local economic growth and status, access to compact electricity demand technologies, the cost of batteries/battery charging services and fuels for fuel-based lighting; as well as:*

- *The technical viability of solar PV equipment: e.g. equipment maturity and reliability under field conditions; projected or expected expansion of the local electrical grid.*

- Local RE Market Potential

    a. Approach for assessing local RE market Potential

    *Comparison of electricity system (solar PV) costs for the consumer relative to the costs of kerosene and batteries, as shown above, and below, is one measure; however, the provision of electricity will allow for additional energy services beyond just lighting (e.g. cooking, appliances), thus the comparison to baseline (non-electrified) conditions is not an exact one.*

    b. Key Metrics

    *Key metrics for assessing local RE Market potential include the fraction of non-grid-connected households in an area, and the average use of other fuels and energy sources by household, as well as the level of income of households (a measure of the affordability of financing offered under the program.*

- Jurisdictional RE Market Potential (Scale-Up)

    a. Approach for assessing Jurisdictional Market Potential

    *In general, unless there are significant differences in the way that energy is used by rural households across jurisdictions, assessing market potential for the SHS in different jurisdictions will largely be a matter of estimating the number of candidate households in the jurisdiction.*

    b. Key Metrics

    *Fraction of non-grid-connected households in an area, and the average use of other fuels and energy sources by household, as well as the level of income of households*

### C. Financial Assessment

[This section will be completed based on the results of the financing assessment. The table at the front of this section will list the relevant metrics for assessing program/project financing, including financial risk. Relevant metrics[41] for option financing should include at a minimum simple payback[42], discounted payback[43] and net present value (NPV).[44] Other financial metrics that may of interest to lending

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[41] See the following web resource for more details on metrics cited here and footnoted below: http://searchcrm.techtarget.com/answer/Metrics-ROI-IRR-NPV-payback-discounted-payback.

[42] *Simple payback* is calculated by comparing the cumulative cash investment in the program/projects and comparing it against the cumulative benefits, typically year by year in a timeline. Most programs/projects have a significant up-front investment, and then over time, this investment is recouped post deployment with benefits. Eventually, the benefits catch up to and exceed the initial and on-going investments required. The duration from initial investment to the point where the cumulative benefits exceed the costs is the *payback period*.

[43] In *Discounted payback,* the costs and benefits of the project are discounted as they occur over time to take into account the lost opportunity of investing the cash elsewhere (usually set equal to a company's cost of capital) and further by a relative measure of the projects risk (the cost of capital + a risk generated discount rate). For projects with long payback periods, discounted payback periods are more accurate at determining the real payback. As with regular payback period, making investment decisions based purely on payback period can orient the team towards quick payback projects without regard to the ultimate benefit quantity – which is best measured using NPV.

[44] *NPV* is a formula that tallies all of the net benefits of a project (benefits – costs), adjusting all results into today's currency terms. This is different than just tallying up all of the net benefits of a project over a ten-year period without discounting as the cumulative benefits without discounting overstate the overall project value, especially

institutions are the internal rate of return (IRR)[45] and return on investment (ROI) or risk-adjusted ROI.[46] Be sure to address and clearly cite the following items.]

- Financial risk, return, and impact. Two relevant categories of financial risk are ***market*** risk and ***credit*** risk. *Market* risk refers to the risk of a changing conditions in the marketplace that could impact the viability of the RE technology being deployed (for example, advances in technology that make the financed project obsolete). *Credit* risk is the risk that lenders incur by extending credit to borrowers. Lenders take on a risk that borrowers could default on payments.]
- Data sources methods, key assumptions, uncertainty, feasibility issues for each of the financial assessment metrics are described below. General assumptions applied here as well as in the rest of the impacts analysis include an inflation rate of 4% and a discount rate of 5%.
- *For the Bangladesh SHS example, there are at least two possible perspectives from which a financial assessment can be carried out. The first is from the perspective of the individual project, specifically, that of the homeowner. The second is from the perspective of the overall program implementer, that is, IDCOL, and thus from the perspective of the Government of Bangladesh. The two cases require quite different inputs. In the calculations described below and presented in Table 2, we use the perspective of the homeowner to assess financial risk, return, and impact.*

  ***Discounted net cash flow (DCF) and net present value (NPV) of implementation costs.*** The NPV of implementation costs was developed by assembling all costs and income components across the total lifetime of a SHS, which is assumed to be 20 years, though solar PV panels may have a lifetime of 25 years or longer.

  *Total installation costs of USD 420 per panel US were taken from available project documentation. It is assumed that this cost covers all equipment and installation costs. As there are no grid interconnections in this example, the costs avoided by the solar home systems, when*

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when the project has many of the investment costs up-front or in year one, and the benefits are not really kicking in until later years (where the time-value of money discounting reduces the overall value of these benefits). NPV is great at tallying up the net benefits over an investment horizon so that different projects can be compared as to the value they return to the company, but this metric alone does not highlight how long it may take to achieve the benefits (as payback period does).

[45] *IRR* is essentially the interest rate that the project can generate for the borrower, and is calculated as the discount value that when applied in the NPV formula drives the NPV formula to zero. Since IRR calculates the cash flow return for each project, investments in projects can be compared easily to other investment vehicles and to investment hurdle rates (returns vs. risks) established by the lender. But IRR is not a great indicator as to the magnitude of investment needed, benefit value or payback, so the returns may be high, but the investment high, benefits not significant and/or payback (risk) too high.

[46] ROI and risk-adjusted ROI calculates the net benefits (total benefits – total costs) of a project divided by the total costs in a ratio to help highlight the magnitude of potential returns versus costs. An ROI of 150% means that $1 invested in the project will garner the investor $1 of their original investment back + $1.50 in gains. Risk-adjusted ROI is often recommended, as it tallies using the time value of money to discount the benefits and costs over time. Risk-adjusted ROI provides a more conservative ratio, since benefits are usually higher than costs in outgoing years, thus the benefits are discounted and the calculated ratio is lower. Businesses typically expect ROI of at least 100% to usually not more than 400% (although higher is possible). The ROI formula is great at comparing the costs to benefits in a ratio, but does not highlight well the timeliness of the returns, where payback period is better.

*evaluated from the perspective of the homeowner, are the costs of avoided lighting fuel purchases, and the costs of avoided disposable battery purchases. The plant capacity factor was not available in project documentation but is assumed to be 0.23, but with only 70 percent of the electricity produced by the solar panel actually used by the household (due to a combination of losses in the battery charging/discharging system, and to households simply not being able to use all of the electricity generated and stored by the end of a given day. Avoided lighting fuel consumption was derived from project documentation on a per-household basis (96 kg/year).*[47] *Lighting fuel (kerosene) costs were estimated based on a recent report of (likely) wholesale fuel costs in Bangladesh, increased by 40 percent to estimate the cost of fuel delivered in small volumes to rural places.*[48] *Fuel price escalation was assumed to be equal to the general inflation rate.*

*Other variable operations and maintenance (O&M) and fixed O&M costs were not provided in project documentation. Values for these were taken from a US publication on solar PV energy systems (see above). Annual escalation of fixed O&M costs was assumed (2.0%/yr).*

*The financial structure of the project from the householder's perspective includes only loans from financial institutions identified by partner organizations, plus a down payment by the householder equal to 15 percent of the total cost of the system, as described in project documentation. The finance rate for the loan is assumed to be 12% over 3 years.*

*Revenue for the project, or more accurately, avoided costs of energy sources displaced by the solar PV systems, is from avoided lighting fuels and from avoided use of disposable batteries.* Note that in an application of solar PV that was grid-connected, electricity sales to the grid, and avoided grid electricity use, would provide the project revenue.

*With the above inputs, a discounted net cash flow (DNCF) for the project was developed along with a discounted NPV of total implementation costs. The period of analysis covers the entire PV system project lifetime (through 2036). The NCF analysis is done from the perspective of the PV system owner. This means that rather than using the total project installation costs, these costs are annualized, and that annualized stream of costs for debt service is used as one of the cash flows along with the initial equity payment and O&M costs. The sum of DNCF is calculated as:*

$$\sum DNCF = E + \sum DS + \sum FOM + \sum F + \sum VOM + \sum T + \sum R_{PS} + \sum Sub + \sum R_O$$

*Where all values have been discounted to 2017 US dollars:*

*E = initial equity payment by project developer (in this case, by the household)*
*DS = annual debt service payment*
*FOM = annual fixed O&M costs*
*F = annual fuel costs*
*VOM = annual other variable O&M costs*
*T = annual tax payments*
$R_{PS}$ *= annual revenue for power sales*
*Sub = annual government subsidy (feed-in tariff)*
$R_O$ *= annual revenue from other sources (e.g. fly ash sales)*

[47] From Nazmul Haque, "DCOL Solar Home System Program", dated December 2013, and available as https://sustainabledevelopment.un.org/content/documents/4923haque.pdf.
[48] See, for example, http://www.bpc.gov.bd/contactus.php?id=39.

*Note – all cost values are negative; all revenue values are positive.*

*The DCF for a solar home system purchased in 2017 under the SHS program is shown from the household's perspective in Table 2, below. The sum of DCF for the household is shown to be $1,752 ($2017) per household for a 50 W PV system.*

*The NCF analysis involves subtracting the total costs from the project revenues in each year. These annual net costs are then discounted back to $2017 using the 10% nominal (including inflation) discount rate.* For other types of renewable energy projects, separate NCF estimates are typically calculated from the perspective of the project developer, as well as for the project overall. The difference is that the NCF for the project developer takes into account the financing assumptions on total installation costs, while the NCF for the project overall excludes these (i.e. costs in year 1 include total installation costs). *The discounted NCF values reported in the summary table above and in Table 2 below are from the perspective of the household. The financial flows from the householder perspective are summarized in Table 3, below. In this case, there is a high levelized cost of electricity (which includes capital and O&M costs, but not project benefits), but it is more than offset by the savings in avoided lighting fuel and batteries that the household receives, as reflected in the rapid payback—which is likely essential for rural households. Figures 6 and 7 show, respectively, the elements of the undiscounted and discounted cash flow from the householder perspectives.*

**Table 2: Summary Outputs of Financial Analysis**

| | | |
|---|---|---|
| **Discounted Net Cash Flow - NCF ($2017)** | **$1,752** | 2017-2036 Project Owner's NPV |
| **Net Present Value - NPV ($2017)** | **$1,701** | 2017-2036 Total Project Base NPV |
| **Internal Rate of Return (IRR)** pre tax | **75.72%** | |
| **Return on Investment - ROI (%)** pre tax | **1055.47%** | Project Owner, Undiscounted |
| **Return on Investment - ROI (%)** pre tax | **461.26%** | Project Owner, Risk-Adjusted |
| **Social Return on Investment - SROI (%)** pre tax | | Project Owner |
| **Simple Payback Period (years)** | **2.01** | |
| **Benefit- Cost (BC) Ratio** pre tax | **5.61** | Project Owner |
| **Levelized Cost of Electricity (LCOE -$/kwh)** | **0.75** | $/kWh, Undiscounted |
| **NPV of Implementation Costs (Owner's perspective)** | **$ 379.73** | Debt service plus O&M |
| **Magnitude of initial investment** | **$ 420.00** | |

***Risk-Adjusted Return on Investment (ROI).*** *As shown in Table 2, the risk-adjusted (discounted) ROI from the householder perspective is over 460 percent, implying that the discounted net benefits are nearly five times the discounted costs of the projects, on average.*

## Table 3: Financial Flows Summary: Bangladesh Solar Home System Project, Household Perspective

| Financial Analysis - 50 Watt Solar Home System | | | | | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Implementation Phase | Period | Year | Total installation Costs ($) | Equity ($) | Debt Service ($) | Fuel Costs ($) | Other Variable O&M ($) | Fixed O&M ($) | Taxes ($) | Renewable Energy Credits Revenue ($) | Net Generation (Wh) | Power Revenue ($) | Feed-In Tariff ($) | Other Revenue ($) | Developer's Net Cash Flow ($) | Developer's Discounted NCF ($2017) | Project Discounted NCF ($2017) | Depreciated Value of Plant ($) | Discounted Costs ($2017) | Discounted Benefits ($2017) | Cumulative Cash Flows | Net Cash Flows |
| Installation and First Year of Operation | 1 | 2017 | ($420) | ($63) | ($111.87) | $0 | $0 | ($1.00) | $0 | $0 | 70,000 | $0 | $0 | $172 | ($3) | ($3) | ($248.60) | $420 | ($176) | $172 | ($421) | ($249) |
| Continued Operation | 2 | 2018 | $0 | $0 | ($111.87) | $0 | $0 | ($1.02) | $0 | $0 | 70,000 | $0 | $0 | $179 | $66 | $60 | $162.07 | $399 | ($103) | $163 | ($1) | $178 |
| | 3 | 2019 | $0 | $0 | ($111.87) | $0 | $0 | ($1.04) | $0 | $0 | 70,000 | $0 | $0 | $186 | $74 | $61 | $153.25 | $378 | ($93) | $154 | $185 | $185 |
| | 4 | 2020 | $0 | $0 | $0 | $0 | $0 | ($1.06) | $0 | $0 | 70,000 | $0 | $0 | $194 | $193 | $145 | $144.90 | $357 | ($1) | $146 | $378 | $193 |
| | 5 | 2021 | $0 | $0 | $0 | $0 | $0 | ($1.08) | $0 | $0 | 70,000 | $0 | $0 | $202 | $201 | $137 | $137.01 | $336 | ($1) | $138 | $579 | $201 |
| | 6 | 2022 | $0 | $0 | $0 | $0 | $0 | ($1.10) | $0 | $0 | 70,000 | $0 | $0 | $210 | $209 | $130 | $129.55 | $315 | ($1) | $130 | $788 | $209 |
| | 7 | 2023 | $0 | $0 | $0 | $0 | $0 | ($1.13) | $0 | $0 | 70,000 | $0 | $0 | $218 | $217 | $122 | $122.50 | $294 | ($1) | $123 | $1,005 | $217 |
| | 8 | 2024 | $0 | $0 | $0 | $0 | $0 | ($1.15) | $0 | $0 | 70,000 | $0 | $0 | $227 | $226 | $116 | $115.83 | $273 | ($1) | $116 | $1,230 | $226 |
| | 9 | 2025 | $0 | $0 | $0 | $0 | $0 | ($1.17) | $0 | $0 | 70,000 | $0 | $0 | $236 | $235 | $110 | $109.52 | $252 | ($1) | $110 | $1,465 | $235 |
| | 10 | 2026 | $0 | $0 | $0 | $0 | $0 | ($1.20) | $0 | $0 | 70,000 | $0 | $0 | $245 | $244 | $104 | $103.56 | $231 | ($1) | $104 | $1,709 | $244 |
| | 11 | 2027 | $0 | $0 | $0 | $0 | $0 | ($1.22) | $0 | $0 | 70,000 | $0 | $0 | $255 | $254 | $98 | $97.92 | $210 | ($0) | $98 | $1,963 | $254 |
| | 12 | 2028 | $0 | $0 | $0 | $0 | $0 | ($1.24) | $0 | $0 | 70,000 | $0 | $0 | $265 | $264 | $93 | $92.59 | $189 | ($0) | $93 | $2,227 | $264 |
| | 13 | 2029 | $0 | $0 | $0 | $0 | $0 | ($1.27) | $0 | $0 | 70,000 | $0 | $0 | $276 | $275 | $88 | $87.54 | $168 | ($0) | $88 | $2,502 | $275 |
| | 14 | 2030 | $0 | $0 | $0 | $0 | $0 | ($1.29) | $0 | $0 | 70,000 | $0 | $0 | $287 | $286 | $83 | $82.78 | $147 | ($0) | $83 | $2,788 | $286 |
| | 15 | 2031 | $0 | $0 | $0 | $0 | $0 | ($1.32) | $0 | $0 | 70,000 | $0 | $0 | $299 | $297 | $78 | $78.27 | $126 | ($0) | $79 | $3,085 | $297 |
| | 16 | 2032 | $0 | $0 | $0 | $0 | $0 | ($1.35) | $0 | $0 | 70,000 | $0 | $0 | $310 | $309 | $74 | $74.00 | $105 | ($0) | $74 | $3,394 | $309 |
| | 17 | 2033 | $0 | $0 | $0 | $0 | $0 | ($1.37) | $0 | $0 | 70,000 | $0 | $0 | $323 | $322 | $70 | $69.97 | $84 | ($0) | $70 | $3,716 | $322 |
| | 18 | 2034 | $0 | $0 | $0 | $0 | $0 | ($1.40) | $0 | $0 | 70,000 | $0 | $0 | $336 | $334 | $66 | $66.16 | $63 | ($0) | $66 | $4,050 | $334 |
| | 19 | 2035 | $0 | $0 | $0 | $0 | $0 | ($1.43) | $0 | $0 | 70,000 | $0 | $0 | $349 | $348 | $63 | $62.56 | $42 | ($0) | $63 | $4,398 | $348 |
| | 20 | 2036 | $0 | $0 | $0 | $0 | $0 | ($1.46) | $0 | $0 | 70,000 | $0 | $0 | $363 | $362 | $59 | $59.15 | $21 | ($0) | $59 | $4,760 | $362 |

**Figure 6:**

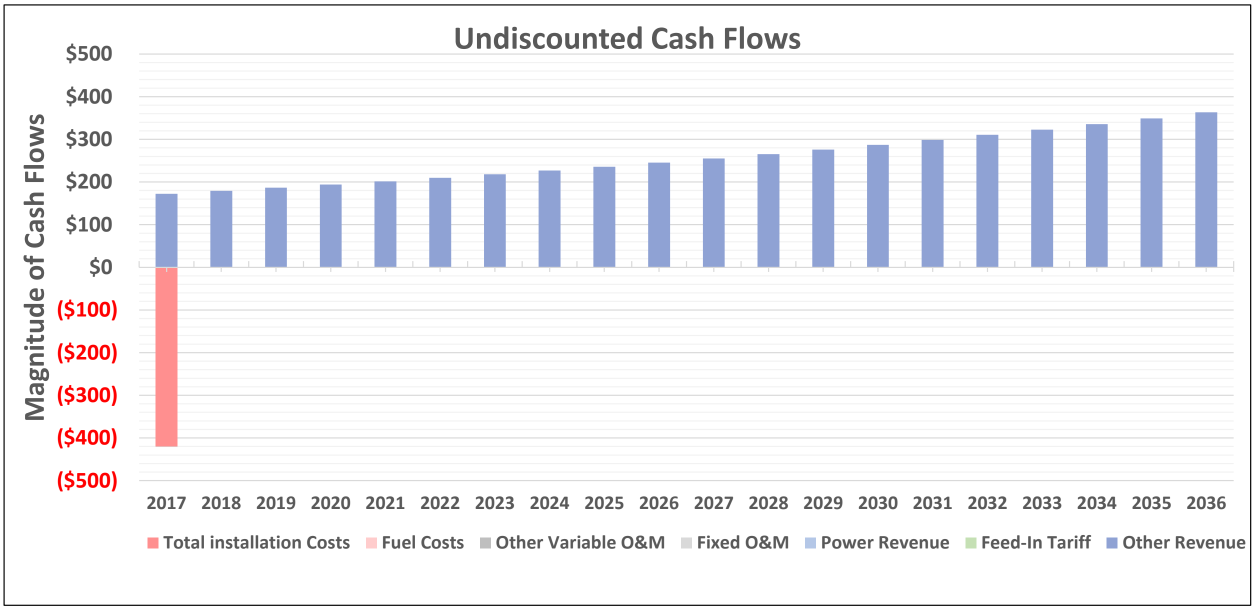
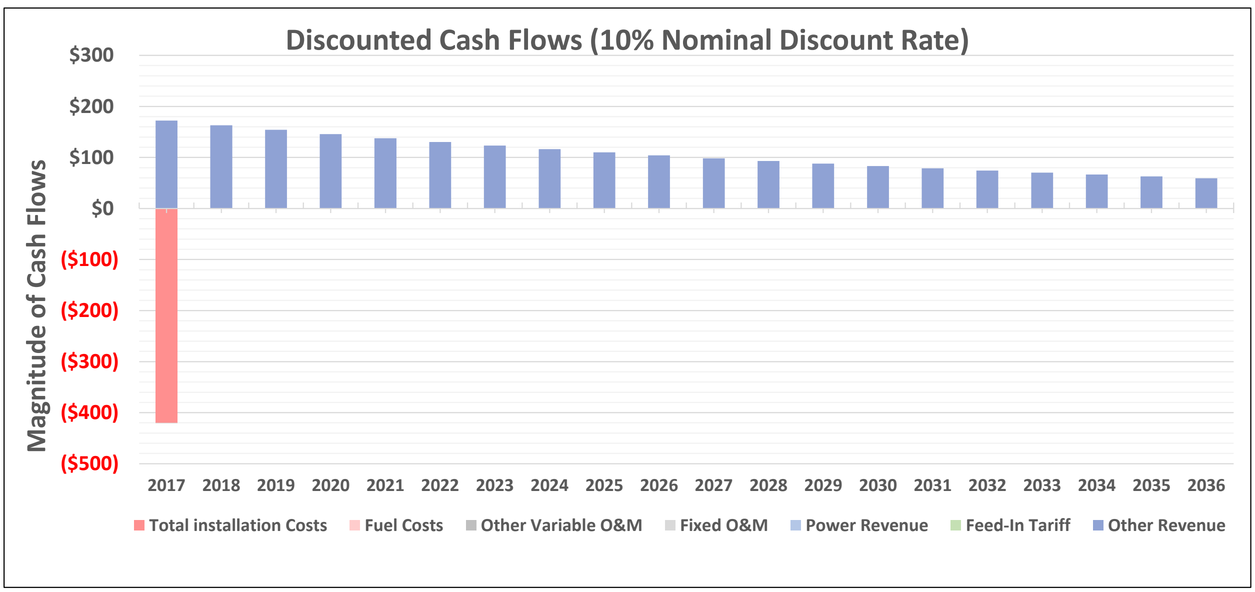



**Figure 7:**




### D. Trading and Other Policies

[Identify any linkages to national cap and trade programs, international carbon programs, or other policies.]

- Data sources methods, key assumptions, uncertainty, feasibility issues

*There has been as yet no indication that the Bangladesh SHS program is linked to any carbon trading program, either national or international.*

More generically, some of the issues associated with solar PV programs in conjunction with trading programs and other policies are likely to include:

- Applicability and value of any relevant carbon offsets, renewable energy credits, or other attributes derived from the program, and the mechanisms for making those financial flows available to fund program elements.

## Additional Impacts

[If needed, this section can include outcomes or outputs of analysis that are not included in the quantification section and the metrics it covers, and can include a more limited approach to analysis or qualitative discussion of key impacts.]

*Beyond the impacts of the program on greenhouse gas emissions, additional impacts of the Solar Home System program in Bangladesh will likely include:*

- *A reduction in indoor, local and regional air pollutant emissions.*
- *An increase in employment for industries associated with manufacturing, retailing, and installing solar PV systems, as well as businesses associated with providing customer support, training, and, program assessment.*
- *A reduction in solid wastes associated with battery usage.*
- *Enhanced residential consumer involvement in and awareness of their energy use and the sources of the energy they use.*
- *Enhanced opportunities for education and nighttime productive activities among householders.*

## Status of Approvals

[This reflects the status of the option as it moves through the decision making and assessment process from conception to final recommendation.]

## Annex: Details of Market Evaluation Methods used in the Bangladesh SHS Program

*Additional details of the market evaluation and related approaches to ex-ante and ex-post analyses of the Bangladesh SHS program include the following:*

> *The potential market size (potential demand) for different classes of technology products was estimated by developing a demand function, constructed from the* ***contingent valuation method (CV)*** *results (through specially designed questionnaire). This function describes* <u>*the local and time- specific demand*</u> *for different solar PV system classes (categorized by Watts of maximum power output).*
>
> *The theory behind the estimation of mean willingness to pay (WTP) concept addressed in the ex-ante program analysis is explained as follows. Assume that the household's utility depends on a composite commodity X and leftover money (Y) available for paying for a SHS. Utility has a deterministic component (first and second terms of the right-hand side of the equation (1)) and a stochastic component, ε. Utility of the household before answering the CV question is:*

$$u_0 = X_0\beta + \gamma Y + \varepsilon_0 \qquad (1)$$

*The utility of the household can be given by equation (2) if the household answered yes to the CV question, where WTP is the maximum amount of money the household is willing to give up to purchase a SHS.*

$$u_1 = X_1\beta + \gamma (Y - WTP) + \varepsilon_1 \qquad (2)$$

*By subtracting (2) from (1),*

$$u_o - u_1 = (X_o - X_1)\beta + \gamma WTP + \varepsilon_o - \varepsilon_1 \qquad (3)$$

*By replacing ($X_0$-$X_1$) as X,*

$$u_o - u_1 = X\beta + \gamma WTP + \varepsilon_o - \varepsilon_1 \qquad (4)$$

*By taking expectation on both sides*

$$E[u_o - u_1] = E[X] \bullet E[\beta] + E[\gamma] \bullet E[WTP] + E[\varepsilon_o - \varepsilon_1] \qquad (5)$$

*Since E(β)=β and E(γ) = γ, the simplification results*

$$E[u_o - u_1] = E[X] \bullet \beta + \gamma \bullet E[WTP] + E[\varepsilon_o - \varepsilon_1] \qquad (6)$$

*In answering the questions on CV, the households responds by maintaining the same level of utility while giving up the amount of money equal to WTP (the bid offer), and acquires the improved services. Thus,*

$$0 = E[X] \bullet \beta + \gamma \bullet E[WTP] \qquad (7)$$

*Therefore, Mean WTP for the sample is:*

$$E[WTP] = -(E[X] \bullet \beta) / (\gamma) \qquad (8)$$

*Equation (8) provides the estimates for Mean WTP for the sample in the study."*

**4.**

**Figure A-1: Measurement of WTP and Consumer's Surplus**

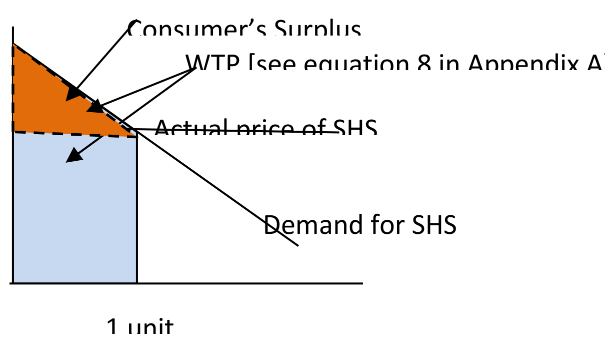


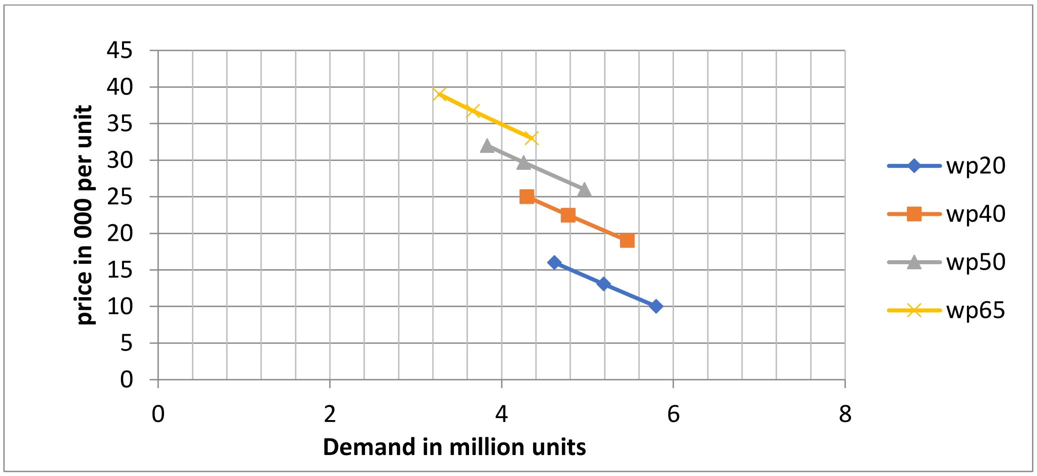

**Table A-1: WTP for SHS in Off-grid Areas of Bangladesh**

| Size of SHS | WTP | Actual price paid by households for purchasing SHS | Consumer's surplus | Probability of purchase |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| **At sample mean** | **24,028.64** | **18,283.84** | **5,744.80** | **32%** |
| for Wp20 | 37,691.30 | 12,560.70 | 25,130.60 | 62% |
| for Wp40 | 42,838.81 | 22,885.24 | 19,953.57 | 14% |
| for Wp50 | 50,098.05 | 28,157.52 | 21,940.53 | 12% |
| For Wp65 | 57,569.55 | 33,609.69 | 23,959.86 | 11% |

5. Source: Estimate based on BIDS survey 2012.

**Figure A-2: Demand Curve for Different Solar PV Products**



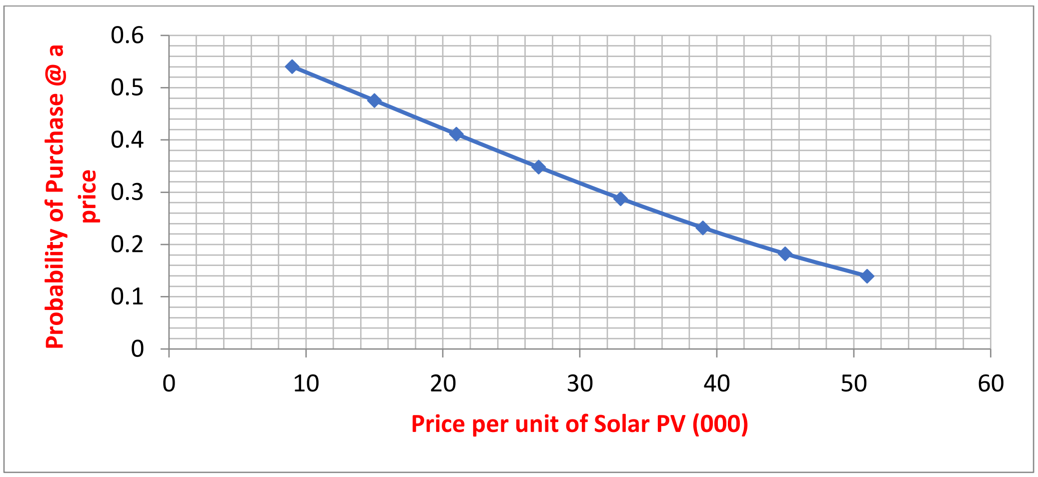

*Data collected through CV questionnaire are further analyzed via Probit model.* ***Probit regression*** *is a statistical method used here to estimate the probability of purchases at different prices. Probit model is a type of regression analysis used to model binary outcome variables. It is applied here to determine what variables are the most statistically significant predictors for purchases of different solar PV product classes (categorized by Wats of maximum power output). These results serve to further improve demand prediction capabilities for the given technology, given that information on future trends and dynamics of relevant variables is available. The analyzed variables were primarily selected as a result of an earlier survey to potential customers which resulted in the identification of the most significant reasons for purchasing the solar PV products, as expressed by the households.*

**Table A-2: Probit Estimates on the Purchase Decision on Solar PV Systems based on CV Questions**

| Dependent Variable: Purchase (yes=1, no=0) | | | | | | |
|---|---|---|---|---|---|---|
| Variables | Expected signs | Coefficient | sig | Marginal Effect | sig | Average |
| Price of SHS (000 taka) | (-) | -0.0419 | *** | -0.0152) | *** | 24.84 |
| Dummy for Wp 40 (Wp 40 = 1) | (+) | 0.3068 | *** | 0.1157 | *** | 0.14 |
| Dummy for Wp 50 (Wp 50 = 1) | (+) | 0.4946 | *** | 0.1913 | *** | 0.12 |
| Dummy for Wp 65 (Wp 65 = 1) | (+) | 0.6540 | *** | 0.2559 | *** | 0.11 |
| Housing Quality Index † | (+) | 0.3475 | *** | 0.1244 | *** | 0.98 |

| | | | | | | |
|---|---|---|---|---|---|---|
| No of Students in the Household | (+) | 0.1775 | *** | 0.0638 | *** | 1.13 |
| Farm Size ᴛᴛ | (+) | 0.3068 | *** | 0.1111 | *** | 1.08 |
| Need for Education (Yes = 1) | (+) | 2.2577 | *** | 0.6539 | *** | 0.03 |
| Need for entertainment (Yes = 1) | (+) | 1.1503 | *** | 0.4324 | *** | 0.02 |
| Need for better quality light (Yes = 1) | (+) | 1.9133 | *** | 0.6102 | *** | 0.02 |
| Income (TK. Per month) | (+) | 0.0041 | ** | 0.0014 | * | 6.34 |
| Constant | | -0.6396 | *** | | | |
| Number of Observations | | 2905 | | | | |
| Pseudo R-square | | 0.3273 | | | | |
| Log Likelihood | | -1311.5636 | | | | |
| LR $chi^2(11)$ | | 1277.98 | *** | | | |

**Figure A-3: Probability of Purchase of Solar PV at Different Prices**




**Elasticity of market demand** estimation method used here is….

### *Ex post Market Assessment (For Demand Assessment and Program Effectiveness Evaluation)*

*One of the priority objectives of ex post market assessment analysis is to validate the role and significance of product demand drivers identified during the ex-ante demand assessment described earlier. Other objectives are the assessment of institutional readiness and performance, financing mechanism effectiveness, consumer feedback, technology performance and potential in the local setting, etc.*

*For preliminary insights on what variables may influence the households' decision to adopt the solar PV product,* ***bivariate tables (cross-tabulations or comparison of means) method*** *was applied. Here, for the pertinent variables, such as the level of education of the households' head, debt and equity holdings of the households, gender of the households' heads, age, etc., the means were computed for adopter and non-adopter households and simply compared against each other in a tabular format.*

*Afterwards, the* ***logistic regression method*** *was applied to go a step further and determine individual and independent influence of the above listed variables on the dependent variable (the solar product adoption in this case, in a binary form). Logistic regression is an* *econometric method used to predict influence of a series of nominal, ordinal, or ratio-level independent variables on one binary variable.*

**Table A-3: Logistic Regression Explaining Acquisition of Solar PV Systems**

6. (SPV = 1; Non-SPV=0)

| Independent variables | Coefficient | Sig. level | Odds-ratio |
|---|---|---|---|
| Annual HH Income up to Tk. 50,000 | Ref | | |
| Annual HH Income between Tk. 50,000 and 100,000 | .186 | .211 | 1.204 |
| Annual HH Income Tk. 100,000 and above | .795 | .000 | 2.214 |
| HH head is male | Ref | | |
| HH head is female | .605 | .022 | 1.831 |
| Age of HH head up to 20 years | Ref | | |
| Age of HH head between 20 and 30 years | -.125 | .852 | .882 |
| Age of HH head between 30 and 50 years | -.138 | .833 | .871 |
| Age of HH head 50 years and above | -.136 | .836 | .873 |
| HH head's education less than primary | Ref | | |
| HH head's education at least primary | .569 | .000 | 1.767 |
| HH head's occupation others | Ref | | |
| HH head's occupation non-agriculture | .444 | .000 | 1.559 |
| No primary educated woman in the HH | Ref | | |
| Primary educated woman in the HH | .327 | .011 | 1.386 |
| Constant | .409 | .537 | 1.505 |
| -2 log likelihood | 1879.70 | | |

*Further, a **Poisson regression method** was used to evaluate the correlation and magnitude of impact of certain variables to the size of PV products purchased. These provide further differentiation and understanding of most important factors' impacts on individual product segments, which can serve to further project the market demand outlook for different sizes of PV products. Poisson regression is used to evaluate the correlation between the explanatory variables and the dependent variable which is expected to follow a Poisson distribution (as oppose to normal distribution assumed in ordinary least square regressions). In this case, the dependent variable is **watt-peaks.***

*The model evaluated in this example is as follows:*

***Wp = 2.73 + 0.0658 ln income + 0.068 eddum – 0.067 Occdum + 0.074 Wed +***

***(0.003) (0.008) (0.008) (0.009)***

***0.135 ln age - 0.026 POdum – 0.132 Instaldum;***

***(0.013) (0,008) (0.009)***

*Where:*

***Wp** is capacity of solar PV products in watt-peak;*

***Income** is household's annual income in BDT;*

***Eddum*** *is dummy for household head's education taking value 1 for at least primary passed; 0 otherwise*

***Occdum*** *is household head's occupation dummy with non-ag -1; 0 otherwise*

***Wed*** *is a dummy for family having at least one primary passed female– 1 for yes, 0 for none*

***Age*** *is household head' age;*

***POdum*** *dummy for Grameen Shakti – 1; 0 otherwise*

***Instaldum*** *is dummy for year of installation – 0 for before 2009*

# Attachment D. Technology Implementation Document Sample - Biomass

**Small Scale Biomass Power from Rice Husk [Label/#]**

This Technology Policy Implementation Document (TPID) template is used for each draft priority technology/policy option to document its status and the details of its development to support stepwise decision making and transparency needs.

*Upfront Considerations for Biomass Power Projects:*

- *Specification of End-Use Technology – this example considers small-scale biomass for power generation (e.g. <30 MW capacity); other alternatives could include biomass co-firing at existing facilities; biomass use for combined heat and power for commercial, institutional or industrial applications*
- *Biomass Fuel Requirements – volumes of available sustainable supply; physical form of fuel (e.g. chipped/shredded, pelletized, or torrefied biomass)*
- *Biomass Feedstocks – sourced within an economically-recoverable zone (e.g. 50 km); could include crop residue (straw or husks), energy crops, wood/municipal solid waste, forest residue. Note: this design radius follows a commonly-applied biomass project planning concept "30 by 30", meaning a capacity of around 30 MW would most often be economically served by biomass resources within a 30 mile (around 50 km).*

**Option Description**

[Provide a general concept description or "overview" of the technology/policy option including its purpose and the rationale behind it and generally how it will be implemented to reach goals, including local feasibility. The "purpose" can also be thought of in terms of its intended effects and will typically fall into one of two categories: technology adoption or change in practice. The "rationale" involves mapping to objectives (e.g. sustainable development, economic vision and goals, equity, others). If the option is related to existing policies in the nation/subnational area, then this should be noted. Typical length: 1-3 paragraphs. Include a general description of the implementation model and its key mechanisms (finance, law, etc.). Also indicate any key co-benefits or disbenefits, including land use change, or environmental benefits, including air quality, water quality/conservation, etc.]]

*This option addresses the construction and operation of the Roi-et Green Thermal Power Plant in Roi-et Province, Thailand, as well as subsequent scale-up of the technology to the national level. The 9.9 MW Roi-et facility will use rice husk as a fuel source.[49]As a result, no impacts to land use are expected, since*

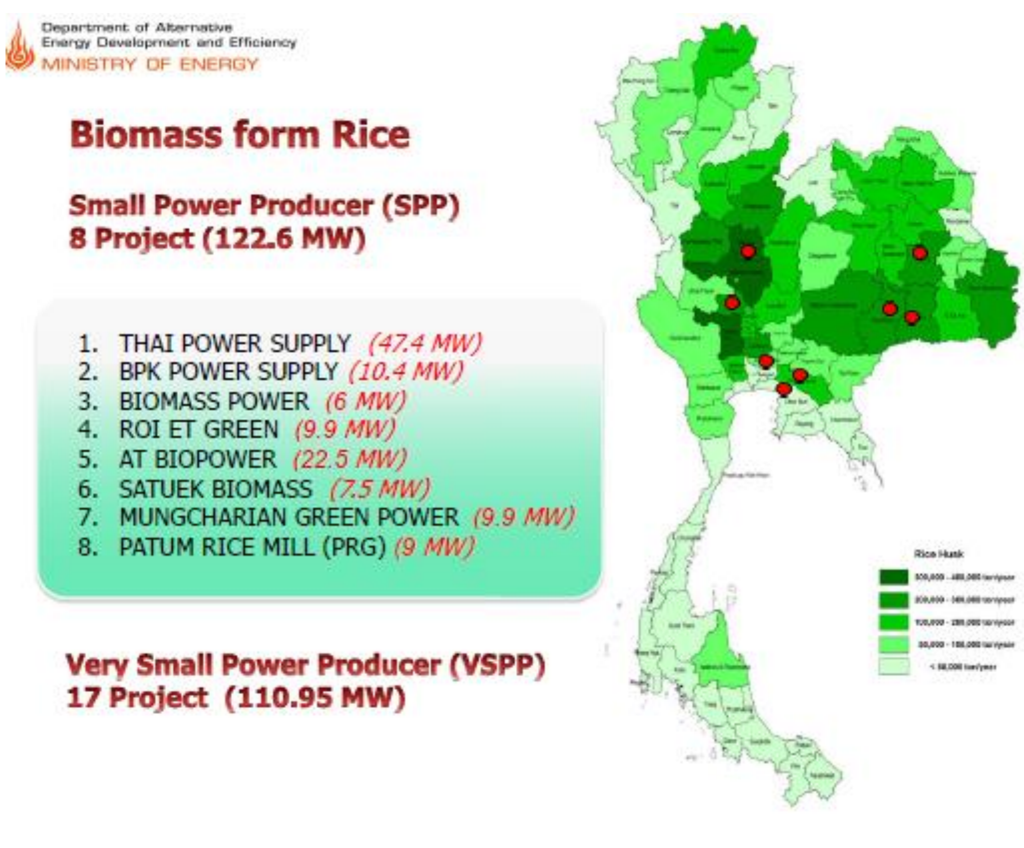
[49] 9.9 MW capacity; 85,000 tons of rice husk per year; annual power generation 58,600 MWh. http://thailand.ahk.de/uploads/media/01_Overview_of_Biomass_Power_Project_in_Thailand_DEDE.pdf.

*no change to business as usual (BAU) crop cultivation is required. Local air quality benefits are expected, since the rice husk will no longer be disposed via open burning as is the case under BAU conditions.*

*The option addresses all actions needed by government, private developers, feedstock providers, and lenders to construct and operate the project. This includes initial biomass supply assessments across all possible feedstocks by the Department of Alternative Energy Development within the Ministry of Energy, provision of feed-in tariffs and special adders by the national government of Thailand (National Energy Policy Council), and other supporting measures. The Implementation Model is further detailed in subsequent sections below.*

*The Roi-et Green Plant will contribute to the country's renewable energy targets (25% Alternative Energy in total energy consumption by 2021)*[50]*, energy security, and local job creation, in addition to reducing greenhouse gas (GHG) emissions as compared to the business as usual (BAU) electricity system. It will supply about 1/3rd of the power demand for Roi-et Province. It is one of several small biomass generating facilities using rice husks that has been identified for construction (see Figure 1 below). The Roi-et Green Power Generating Plant (see Figure 2) is an early pilot project and when successfully demonstrated, should promote scaling of similar biomass power projects in the rest of the country.*

***Figure 1. Planned Biomass Power Projects from Rice Husk Feedstock***




[50] From the Alternative Energy Development Plan (AEDP), alternative energy sources include bio-energy (including biomass, biogas, and municipal solid waste), solar, wind, biofuels, hydro, and "new energy" (ocean and geothermal).

***Figure 2. Roi-et Green Power Plant***

## Option Design and Implementation

[This section outlines the "what you do and how you do it" aspects of the option with a series of breakdowns.]

### Goals

[Specific, clearly defined, numeric metrics that address goals and objectives of the option, with explanation as needed. Goals should be expressed in units appropriate to the policy and its objectives, i.e., % of market penetration and access to technology, number of installations, quantity produced, acres affected, jobs created, risks avoided, etc. These should be achieved over and above existing and planned (business as usual or BAU levels).]

- *Complete work on supporting mechanisms by 2019 (see Implementation Model section below);*
- *Complete all phases of planning, engineering, permitting and construction by 2019; includes extension of transmission system to the plant site; and*
- *Begin operation of the Roi-et Green Plant by January 2020. This includes identification and contracting of biomass suppliers.*

### Location

[Identify specific geographic location and scale.]

*Central Roi-et Province, Thailand: specify physical address or coordinates.*

### Timing

[Identify start, ramp up, completion, and other any important timing requirements, assumptions or concerns.]

*The timing specified above allows for two and a half years of planning (including supporting mechanisms), site acquisition, engineering, construction, and contracting for feedstocks. This includes construction of tie-ins to the local electrical grid.*

### Other

[Use this to indicate any pertinent option design features or issues not covered above. These could be exemptions or thresholds which include or exclude involved entities.]

### Implementation Model

[Summary description of the overall process by which the option is moved from startup to final implementation, including a diagram that shows each of the phases and the parties involved and requirements needed for each stage of decisions, including metrics in a table with supporting narrative on stepwise procedures.]

**Table 1. Roi-et Green Power Plant Implementation Model**

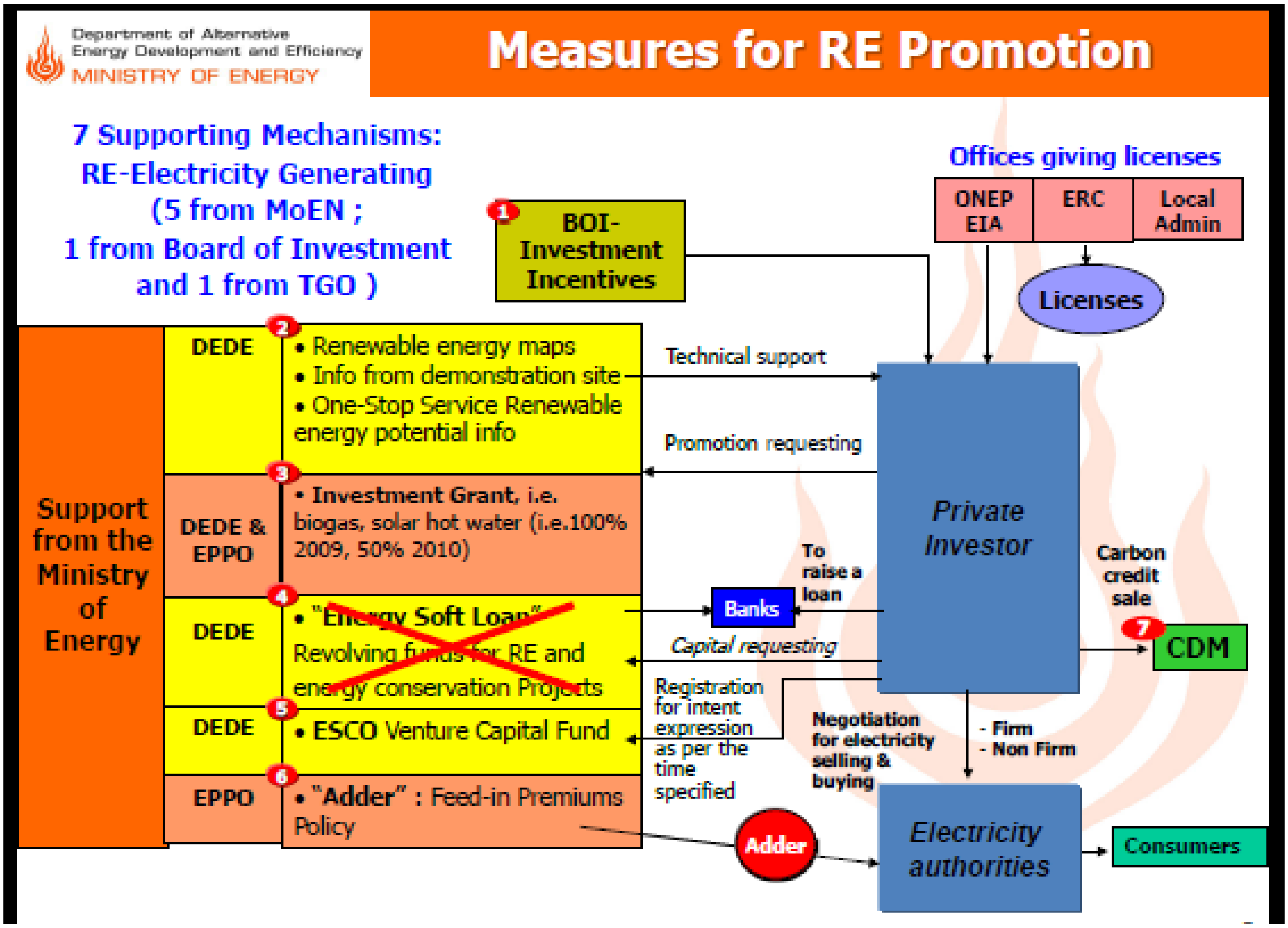
| Phase | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| **Phase Name** | Develop & Implement Supporting Mechanisms | Project Concept & Business Plan | Feasibility Study | Biomass Fuel Contracts & PPA | Permitting & Preliminary Engineering |
| **Parties Involved** | • Department of Alternative Energy Development and Efficiency (DEDE)<br>• National Energy Policy Council (NEPC)<br>• Thailand Energy Policy Planning Office (EPPO) | • Electricity Generating Public Company (EGCO; Project Developer) for review by -<br>• Electricity Generating Authority of Thailand (EGAT) | • EGCO for review by -<br>• EGAT | • EGCO negotiates with<br>• Som Mai Roi-et Rice Mill (Biomass Fuel Supplier) | • EGCO and Permit Authorities for permitting<br>• EGAT engineering for T&D system extension |
| **Legal, Policy, Administrative, and Financial Mechanisms** | Develop Feed-in Tariffs and Special Adders (NEPC)<br>Develop renewable energy maps for Project Developers and Information from Demonstration Projects (EPPO and DEDE) | Proposed Power Purchase Agreement (PPA)<br>Agreement from EGAT on providing the transmission grid tie-in. | EGAT-Accepted PPA (8.8 MW for 21 years)<br>Negotiation of Fuel Contract(s) | Signed Biomass Fuel Contract(s): EGCO and Som Mai Rice Mill<br>Signed PPA | Required permits to construct and operate the facility (including any new feedstock supply processing facilities) |
| **Analytical Requirements** | Biomass Supply Assessments<br>Location of existing and planned T&D infrastructure | Net generation for purchase by the **Local Utility**<br>Plant Construction Costs | Anticipated Financing Structure – e.g. % of debt financed; loan length and interest rate | Detailed long-term biomass supply assessment | Environmental assessments to support permitting |

| Phase | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| | Electricity Demand Assessments<br>Location of ideal locations for biomass projects based on the location of supply, demand needs, and T&D infrastructure | Plant Operations and Maintenance (O&M) Costs<br>Fuel source(s), processing, transportation and delivered costs<br>Capital and O&M Costs for fuel processing facilities | Financial Risk Analysis – return on investment; net present value; etc. | | |
| **Other Requirements** | | Project concept continues to next step with interest by **EGAT** | Note: If equity lenders are expected, developer should bring them in at this stage. Debt lenders can be approached when construction is ready to start. | Note: Som Mai Roi-et Rice Mill granted 5% equity share in the power plant. | Community outreach and engagement to educate the local population on plant operations, environmental impacts/benefits, and economic impacts. |

***Roi-et Power Plant Implementation Model (continued)***

| Steps | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|
| **Phase Name** | Engineering, Procurement and Construction (EPC) Bid Package Development | **EPC Firm** Selection | Funding Negotiations | Plant Construction and Operation Start-Up | Monitoring and Scale-Up of Projects to Jurisdictional Scale |
| **Parties Involved** | **EGCO** and **EPC Bidders** | **EGCO** and **EPC Contractor** | **EGCO** and **Funders [Industrial Finance Capital of Thailand (IFCT), National Board of Investment (BOI), United Nations Global Environment Facility (GEF)]** | **Project Developer, EPC Contractor** and **Lenders** | **EPPO, DEDE** and **EGAT** |
| **Legal, Policy, Administrative, and Financial Mechanisms** | EPC responsibilities, performance requirements, bonding, schedule targets, etc. | EPC Contract | Grant and loan applications and contracts<br>Assess applicability of carbon credit programs (UN Clean Development Mechanism or CDM) | Grant funding received from GEF<br>Soft loans from IFCT and BOI | Biomass energy program communications; promotion of the Roi-et pilot project. |
| **Analytical Requirements** | Assessment of responsible EPC bidders for invitation to bid | Analysis of EPC bids | Financing structure and requirements, financial risk analysis, carbon credit value | | Biomass resource assessment mapping<br>Assessment of local demand growth<br>T&D infrastructure needs |
| **Other Requirements** | | Note lenders may require EPC performance guarantees and bond | | | |

***Figure 3. Financial Mapping Chart***



**Planning and Implementation Phases**

[[Expand the discussion of each Phase outlined in the Implementation Model above. In Phase 1, identify the initial formative planning requirements needed to support initiation of implementation in subsequent phases of the model. In the final phase, describe what is needed to monitor success of the program/project and to scale-up implementation of similar programs/projects to the jurisdictional scale. For each Implementation Phase, identify the: Parties Involved (those affected by outcomes of the option and those involved in its implementation and their roles); as well as their involvement in the specific Implementation Mechanisms which make up each Implementation Phase (including steps within each phase, as needed). Implementation mechanisms are the legal, administrative, and financial mechanisms needed for implementation]

*Please see Table 1 for an overview of the planning and implementation phases used in the Roi-et Green Power Plant project.*

**Phase 1….**

**Phase 2…**

**Phase 3…**

**Parties Involved**

[Summarize those affected by outcomes of the option and those involved in its implementation and their roles, based on the details provided in the planning and implementation steps above.]

## Baseline Conditions

[This should also capture the relevant elements of any existing and/or planned actions at the subnational/national level that affect implementation of the option. Measures are designed to be incremental to existing and planned actions (baselines). Include a description of any existing program and the relationship to the option (for example, applicable emissions offsets, funding source). In addition to BAU existing/planned actions, also summarize the BAU management of the resource (if any). This would include BAU land use that would be affected by implementation of the option (e.g. conversion of forest or cropland to land used for growing energy crops)]

*Prior to the development of this program in Thailand, there were no other known programs addressing the utilization of rice husk for biomass power generation.*

*As in much of Thailand, most of the electric power in Roi-et Province is produced by thermal power plants fired on distillate and residual oil. We would also want to provide more detail here on the BAU practices in managing rice husk (which appear to be that it is trucked back out to the field for open burning).*

## Metrics for Implementation Assessment

[Create a general equation followed by the procedure by which it will be customized to the technology/policy measure at broad as well as specific level through use of methods and metrics.]

**Energy and RE Technology Demand**

1. Key Issues

[Describe the key issues that need to be addressed. This section addresses both energy demand as well as the market demand for the RE Technology. Reference should be made to the jurisdictional (provincial or municipal) baseline for energy demand to frame the needs for new generation at that scale (e.g. new GW of capacity needed in five year increments through 2050). The local energy demand method is described below.

Estimations of market demand for each RE Technology will be different as a result of the different players in each market. The market for a distributed generation program such as a residential solar PV program option consists of solar PV project developers (sellers) and residential households (buyers). The market for a dedicated RE power plant (e.g. biomass, large scale wind) consists of RE project developers (sellers) and the electricity authority (buyer). Therefore, the methodology for estimating market potential for distributed RE programs versus dedicated RE plants will need to be formulated accordingly]

*Based on the national baseline report, Thailand's electricity demand in 2015 was XX GWh in 2015. Broken down by end use, the residential sector demanded XX%, the commercial/institutional sector XX%, and the industrial sector XX%. Under BAU conditions, electricity demand is expected to grow to XX GWh by 2035. By that year, the residential sector is expected to demand XX% of the total, the commercial/institutional sector XX%, and the industrial sector XX%.*

*The local energy demand for Roi-et Province is described in the next section, and an assessment of RE market demand is then provided.*

2. Methodology: Local Energy Demand

[Include general methods and metrics for the option.]

Estimate energy demand for each end use sector (residential, commercial/institutional, and industrial):

a. Begin with location-specific historical consumption for each end use sector from the relevant electricity authority:
    i. $R_d$, $CI_d$, $I_d$ - Residential, commercial/institutional, and industrial energy demand for the historical base year (MWh). Note: further disaggregation to subsectors is also highly valuable if available (e.g. rural vs. urban residential; commercial vs. institutional; disaggregation for key electricity consumption subsectors)
    ii. For forecasting methods development, consider the provincial-level forecasting methods from the LCD Toolkit as a starting point for further refinement. These are in 2 separate memos located on iMC[51]: one for the residential, commercial and institutional sectors; the other for the industrial sector. Higher levels of sophistication could be added to these forecasting methods to address expected changes in climate (leading to greater demands for heating or cooling); and energy price effects (e.g. elasticity of demand to future prices in electricity).
b. Include equations for estimating local electricity demand by sector and additional details of end use. As a generic example:

[51] https://ccs.imeetcentral.com/ssouthchinare2/folder/WzIwLDkwMTk5Mjhd.

i. Electricity Load Growth = ƒ (population, income growth, climate changes, technology innovation, price elasticity)

ii. Allocation of sector-based load to energy end use: % heating/cooling, lighting, cooking, water heating, remaining plug load.

iii. Diurnal profile summaries of sector-based load by season for key target years.

3. <u>Key Metrics: Local Energy Demand</u>

[Include specific metrics for the option, including data sources, methods, key assumptions.]

a. Electricity and direct fuels price forecasts

b. Elasticity of energy demand by end use sector

c. End use technology mix and shifts (possibly, as a function of income): lights, fans, A/C, refrigeration, appliances, equipment

d. Population, economic and income status and growth (rural versus urban breakdowns)

e. Climate change effects on heating and cooling demand

f. Breakdown of sector demand by end use (lighting, heating, cooling, appliances, other) and technology innovation rate impacts on consumption by end use

g. Sector and total electricity demand diurnal load profiles (by season for key target years)

h. Policy incentives

i. Caps: stringency, baseline GHG intensity, flexibility, value of allowances

ii. Other policies and requirements if/as needed

**Energy Supply**

1. <u>Key Issues</u>

[Describe the key issues that need to be addressed. Summarize the jurisdictional energy supply baseline, including what new generation sources are expected to be put in place in the future under business as usual (BAU) conditions to meet future load growth. Also, how will the RE option being considered impact the BAU generation system (e.g. if it is tied to the grid or not, if it ties to a grid that serves the entire jurisdiction or to a smaller independent grid)?

The remaining sections address the RE technology for this option.]

*Historically, electricity supply has been dominated by distillate and oil-fired thermal power plants. In 2015, the carbon intensity of power supply was XX kg $CO_2$e/MWh (including T&D losses). Under BAU conditions, the carbon intensity of power supply will be XX kg $CO_2$e/MWh by 2035.*

*At the provincial level, the Roi-et Green Power Plant will significantly impact the carbon intensity of delivered power. Its power will be applied to the national grid and will supplant other BAU grid power produced via oil-fired thermal power plants. Its level of generation will be about one-third of the province's demand and GHG emissions will be near zero. This doesn't mean that the carbon intensity of the national grid will be cut by one-third, however.*

2. Methodology: Local RE Supply

   a. Local Resource Assessment

      i. Provincial supply of biomass from rice husks was developed as part of a larger biomass program geo-spatial study effort by DEDE covering the entire nation for various biomass feedstocks (see Figure 1 as an example product of this work). Provincial rice husk production is about 200,000 tons per year.

      ii. Basis for the amount of rice husk available[52].

      iii. Other biomass resources are also potentially available, including rice straw; however, they are considered more expensive to source and transport than rice husk. Note that in the future, additional biomass power plants are expected to compete for the same resource. This could require that the Roi-et Plant plan for expanding acceptable feedstocks in the future or absorb higher prices. In contrast to rice husk, most crop biomass resources will be associated with crop residues (e.g. rice straw). The general equation for estimating crop biomass resource potential from crop residue is:

$$B_a = A_C \times RC \times (1-R_f)$$

where:
$B_a$ = annual biomass resource available (tonnes/yr)
$A_C$ = crop area (hectares/yr)
RC = residue (e.g. straw) production for the crop (tonnes/hectare)
$R_f$ = fraction of crop residue remaining on field (unitless; e.g. amount needed to assure no net losses of soil carbon)

      iv. Source documentation suggests that BAU practices for managing rice husk is to burn it in the field. One would assume that this is the case for rice straw; however, it should be verified that this occurs with rice husk, since this material is located at the rice mill and would have to be transported back to an open field for burning. Regardless, combustion of rice husk at a well-controlled power plant should lead to positive GHG and air pollution benefits as compared to BAU practices.

   b. Supply Technology Considerations:

      i. *Biomass fuel requirements.* From project documentation, the Roi-et Power Plant requires 85,000 tons of rice husk per year as fuel (less than half of provincial availability). The general equation for estimating fuel requirements for biomass power generation is:

$$F_{cons} = PC \times HR \times C_f \times 8760$$

where:
$F_{cons}$ = annual plant fuel consumption (TJ/yr)
PC = Plant capacity (gross MW)
HR = Plant gross heat rate (TJ/gross MWh)

[52] Assuming 20% of rice is husk on a dry weight basis; Roi-et's rice production in 2010 was 984,400 tons; http://www.jyoungeconomist.com/images/stories/17_AED_ch15_pp_235_246_Nattanin.pdf.

$C_f$ = Plant capacity factor (unitless; account for down-time by the plant for maintenance, etc.)
8760 = hours per year

ii. *Plant fuel costs.* The plant will be located within a short distance of the Som Mai Rice Mill; lowering transportation costs and ensuring a more consistent supply. Rice husk transportation costs were estimated using geo-spatial analysis and quotes from local transport companies (baht/tonne-km). Annual fuel costs were then estimated as:

$$AFC = F_{cons} \times FC_{del}$$

where:
AFC = annual fuel cost (baht/yr)
$F_{cons}$ = annual fuel consumption (tonnes/yr)
$FC_{del}$ = delivered fuel cost (baht/tonne)

*iii. Renewable power production.* The general equation for renewable power production is:

$$RP = PC \times C_f \times OU_f \times 8760$$

where:
RP = Renewable power production (MWh/yr)
PC = Plant capacity (gross MW)
$C_f$ = Plant capacity factor (unitless; account for down-time by the plant for maintenance, etc.)
$OU_f$ = Plant own-use factor (unitless; fraction of gross output used on-site for plant needs; sometimes referred to as "parasitic losses")
8760 = hours per year

iv. *Power plant GHG emissions.* The carbon dioxide ($CO_2$) emissions from rice husk combustion are considered carbon neutral. The GHGs accounted for from plant operations, include: nitrous oxide ($N_2O$) and methane ($CH_4$) from rice husk combustion; $CH_4$ from rice husk storage; and $CO_2/CH_4/N_2O$ from on-site fuel combustion (for non-generation purposes) and for rice husk transportation. *Equations and data sources not provided in project documentation*. The general equation for power plant fuel combustion GHG emissions is:

$$AE_{cmb} = F_{cons} \times EF_{GHG} \times 1/1000$$

*where:*
$AE_{cmb}$ = annual emissions of a specified GHG [$CO_2$, $CH_4$, or $N_2O$ (tonnes/yr)]
$F_{cons}$ = annual power plant fuel consumption (TJ)
$EF_{GHG}$ = emission factor for the specified GHG [$CO_2$, $CH_4$, or $N_2O$ (kg/TJ)]
1/1000 = conversion from kg to tonnes

The general equation for biomass fuel transport is:

$$AE_{FT} = [F_{cons}/(TC_b \times H_b)] \times D_t \times F_{econ} \times EF_{GHG} \times 1/10\text{^}6$$

where:
$AE_{FT}$ = annual emissions of a specified GHG (tonnes/yr)

$F_{cons}$ = annual power plant fuel consumption (TJ)
$TC_b$ = truck capacity for biomass transport (tonnes/trip)
$H_b$ = heat content of biomass (TJ/tonne)
$D_t$ = roundtrip distance per trip from biomass supplier to power plant (km/trip)
$F_{econ}$ = average fuel economy of transport truck (TJ/km)
$EF_{GHG}$ = emission factor for the specified GHG [$CO_2$, $CH_4$, or $N_2O$ (g/TJ)]
$1/10^6$ = conversion from g to tonnes

v. Power plant capital and operating costs:

1. Generation characteristics: 9.8 MW gross (nameplate) capacity; 8.8 MW net output contracted to EGAT for 21 years. High pressure steam boiler is used to generate steam for use in a steam turbine generator. Air pollution controls include a multi-cyclone and electro-static precipitator. Based on values from the literature (Lazard, 2016; footnoted below), a typical lifetime for a biomass power plant would be 25 years.

2. Installation costs: *not detailed in the available documentation… Project documentation indicates only that it is >$1.2 MM$/MW;[53].*These costs would normally be obtained from bid documents; break-down of total installation costs into subcategories is useful (initial engineering and permitting, land acquisition, plant construction, tie-in to the electrical grid, etc.). Assuming $1.2 MM/MW and the 9.95 gross capacity of the plant, then the total installation costs are $11,940,000.

3. Operation & maintenance (O&M) costs: *not provide in available documentation..* These would be obtained from bid documents or the literature. Values for this example TPID were taken from the literature.[54] Other variable (non-fuel) O&M costs are $95/kw-yr and fixed O&M costs are $15/MWh (this latter value is based on coal plants, since no value for biomass plants was available). Escalation of O&M costs is also taken from Lazard, 2016 at 2.25%/yr.

4. Fuel costs. Stability of biomass costs and logistics: *not provided in available documentation…* However, the project was greatly advantaged by partnering with the Som Mai Rice Mill (5% equity stake), which offered consistent and cost-effective feedstock. The range in delivered rice husk fuel costs is expected to be $6.97 to $8.29/tonne.[55] The mid-point of this range ($7.63/tonne delivered) was used for this example.

[53] Roi-et Green Power Plant presentation from the Roi-et Green Power Company; http://www.jst.go.jp/asts/asts_j/files/ppt/22_ppt.pdf.
[54] Based on Lazard, 2016 (Levelized Cost of Electricity): https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.
[55] Based on variability in transportation costs (transportation is 20-31% of total delivered cost); Ueasin, N. et al, "Small and very small rice husk power plant transportation network planning in Northeastern Thailand." http://www.jyoungeconomist.com/images/stories/17_AED_ch15_pp_235_246_Nattanin.pdf.

Fuel cost escalation was set at 4.0%/yr, equal to the expected general rate of inflation for this example.

Fuel consumption is 87,600 tonnes of rice husk annually.[56]

Note that generally, for biomass power generation, the form of biomass fed to the plant's boilers can range from chipped fuel to densified biomass pellets to torrefied biomass (wood processed through heating in a low oxygen environment to a charcoal like product). *For Roi-et, the plant was designed for rice husks, which require no processing.*

Biomass Feedstock Location – in the U.S., economically viable feedstock sourcing tends to occur within a 50-75 km radius of the plant. *For Roi-et, documentation states that the plant is located near the rice mill.*

5. Revenue. *The price to be paid for power within the PPA was not provided.* For the purposes of this example, it is assumed to be \$0.10/kWh and that this price is held constant throughout the 21 year PPA.

   Note that documentation states that boiler ash could be sold as a raw material to other industries. However, no information was available on the actual value of boiler ash.

   The following feed-in tariff is applicable during the first 7 years of operation: 0.30 baht/kWh (\$0.0097/kWh). No other renewable energy credits (RECs) or carbon offset credits were assumed to be applicable for this project.

6. Other. *Not provided in project documentation.* The total tax rate is assumed to be 20% of annual revenue. The salvage value of the plant at the end of its useful life is assumed to be \$500,000.

3. Key Metrics

   a. Biomass Technology Capital Costs: \$11.94 million.

   b. Fuel Costs: \$7.63/tonne delivered (escalated at 4.0%/yr).

   c. Operations & Maintenance Costs: Other variable: \$15/MWh; Fixed: \$95/kW-yr (escalated at 2.25%/yr).

   d. Levelized cost of electricity (LCOE) – \$23.18/MWh. Compare to LCOE values for other BAU generation sources. Optimally, these come from the electricity provider (EGAT); or can be estimated, for example, for generic coal and diesel plants, on a "proxy plant" basis. There are several formulas needed to convert the various units into the \$/MWh units used to express levelized costs. These are briefly described below.

[56] Project documentation: 300 tons/day; "Launching Small Power Producer (SPP) employing rice husks as fuel: A case study from Roi-et Green Power Plant"; https://pub.iges.or.jp/contents/APEIS/RISPO/inventory/db/pdf/0139.pdf.

*Initial Investment Costs (IIC)*[57]*:* These costs are annualized to \$/MWh units for each year of expected plant operation as per the formula below:

$$\textit{Annualized IIC} = IIC * FCF * 1000 / (8760 * C_f)$$

where:
IIC = initial investment costs. These include the capital costs of land and equipment, as well as any other initial costs for planning, engineering and construction (\$/kW)
$C_f$ = capacity factor (%)
8760 = hours per year
FCF = fixed charge factor[58]
1000 = conversion from \$/kW to \$/MW

*Fixed O&M (FOM)*[59]*:* These costs are estimated for each year of plant operation in \$/MWh units as per the formula below:

$$\textit{Annualized fixed O\&M cost} = FOM * 1000 / (8760 * C_f)$$

where:
FOM = fixed O&M (\$/kW-yr)
$C_f$ = capacity factor (%)
8760 = hours per year
1000 = conversion from \$/kW to \$/MW

*Variable O&M (VOM)*[60]*:* These costs should already be provided in units of \$/MWh, so no conversion is needed.

*Fuel costs (FC):* Each year's fuel price is converted to units of \$/MWh as follows:

$$\textit{Annual Fuel Cost} = FP_t * HR$$

where:
$FP_t$ = fuel price in year t (\$/TJ)
HR = gross heat rate (TJ/MWh)
t = year in the plant lifetime

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[57] Typically reported in units of \$/kW, these costs include the total costs of construction, including land purchase, land development, permitting, interconnections, equipment, materials and all other components. Construction financing costs are also included.

[58] This factor is calculated based on assumptions regarding the plant lifetime, the effective interest rate or discount rate used to amortize capital costs, and various other factors specific to the power industry. Expressed as a decimal, typical fixed charge factors are typically between 0.10 and 0.20, meaning that the annual cost of ownership of a power generation technology is typically between 10 and 20 percent of the capital cost. Fixed charge factors decrease with longer plant lifetimes, and increase with higher discount or interest rates.

[59] Typically reported in units of \$/kW-yr, these costs are for those that occur on an annual basis regardless of how much the plant operates. They typically include staffing, overhead, regulatory filings, and miscellaneous direct costs.

[60] Typically reported in units of \$/MWh, these costs are for those that occur on an annual basis based on how much the plant operates. They typically include costs associated with maintenance and overhauls, including repairs for forced outages, consumables such as chemicals for pollution control equipment or boiler maintenance, water use, and other environmental compliance costs.

*Discounted Costs:* All of the annual costs estimated above are then discounted as follows:

$$Discounted\ Annual\ Costs = [PV_{GEN} * DR * (1+DR)^t] / [(1 + DR)^t - 1]$$

where:
$PV_{GEN}$ = present value of the sum of all generation costs
= annualized IIC + FOM + VOM + FC ($/MWh in each year of the plant's lifetime)
DR = discount rate

The values in the stream of discounted annualized costs are then levelized across the lifetime of the plant:

$$LCOE = \sum Discounted\ Annual\ Costs/PL$$

where:
LCOE = levelized cost of electricity ($/MWh)
PL = lifetime of the plant (years)

4. Project Impact: *The following at a minimum will be included in our project, but were not developed in available Roi-et Project documentation - GHG reduction from BAU (tonnes of $CO_2$ equivalent or $tCO_2e$); renewable electricity production; contribution toward jurisdictional target(s); job creation*.

## Results of Assessment

[This section is where the quantification results are presented and discussed. The section begins with a standard table that presents key summarized results]

### RE Energy and Emissions Assessment Results

| **Program/Project – Level Results** | | | | |
|---|---|---|---|---|
| **2035 RE Generation (GWh)** | **2020 - 2035 RE Generation (GWh)** | **2035 Power Demand Met (%)** | **2035 GHG Reduction ($tCO_2e$)** | **2020 – 2035 GHG Reduction ($TgCO_2e$)** |
| 61.7 | 925 | 30 | 28,012 | 0.42 |
| **Potential Jurisdictional – Level Impacts** | | | | |
| **2035 RE Generation (GWh)** | **2020 - 2035 RE Generation (GWh)** | **2035 Power Demand Met (%)** | **2035 GHG Reduction ($tCO_2e$)** | **2020 – 2035 GHG Reduction ($TgCO_2e$)** |
| 617 | 9,250 | 12 | 280,120 | 4.2 |

### RE Technology Market Assessment

| Capacity of Resource (GW) | Annual Net Generation (GWh) | Total Electricity Demand (GWh) | Incremental Electricity Demand (GWh) | Metric E |
|---|---|---|---|---|
| *Provincial (Local) Level* | | | | |
| 30 | 180 | | | |
| *Jurisdictional (National) Scale-Up* | | | | |
| 300 | 1,800 | | | |

**Program/Project Financial Assessment**

| **Program/Project – Level Results** | | | | |
|---|---|---|---|---|
| **Initial Investment Costs ($MM2017)** | **Discounted Net Cash Flow 2018-2041 ($MM 2017)** | **NPV of Implementation Costs 2018-2041 ($MM 2017)** | **Internal Rate of Return (%)** | **Risk-Adjusted Return on Investment (%)** |
| -11.9 | 24.2 | 76.8 | 93 | 46 |

### A. Jurisdictional and Local Energy Supply and Demand

[This section will be completed based on the results of the demand/supply assessments, financing, and trading and other ancillary policy impacts. List the relevant metrics and results, perhaps in table to simplify, and then provide a step-wise description of the process used for evaluating metrics.]

- **Direct, Indirect, and Integrative Impacts**
  - [This section is where the summary of results for energy supply and demand provided above is documented. This also is where a link or reference to more detailed analysis and results can be found. Direct results include power generation/other energy and emissions impacts. Indirect results should either be quantified or at least qualitatively cited. These include energy and emissions impacts on upstream fuel supplies. Integrative impacts include jurisdictional level generation and emissions impacts resulting from scaling the technology up to that scale]
- **Key Uncertainties**
  - [This section addresses key uncertainties and any methods for addressing them in quantification results above.]
- **Feasibility Issues**
  - [This section addresses key feasibility issues identified and addressed or not addressed in the assessment and their implications.]

### B. RE Technology Demand

[Summarize the results of the RE technology market assessment summarized in the table at the beginning of this section.] The following factors are important to understanding RE market potential for rice husk-based biomass power generation in Roi-et Province: provincial electricity demand, in particular, the need for new baseload power for the electrical grid; available rice husk; levelized cost of electricity (LCOE) for rice husk based power versus other alternatives (including fossil fuels); and financial risk analysis (see Subsection C below).

- Technical viability: e.g. equipment feasibility/maturity; feedstock availability; baseload demand growth for the local electrical grid.
- Local RE Market Potential

  a. Approach for assessing local RE market Potential

  Comparison of the LCOE for the technology to other alternatives with and without incentives; etc.

  b. Key Metrics

  Jurisdictional RE Market Potential (Scale-Up)

  c. Approach for assessing Jurisdictional Market Potential

  d. Key Metrics

### C. Financial Assessment

[This section will be completed based on the results of the financing assessment. The table at the front of this section will list the relevant metrics for assessing program/project financing, including financial risk. Relevant metrics[61] for option financing should include at a minimum simple payback[62], discounted payback[63] and net present value (NPV).[64] Other financial metrics that may of interest to lending

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[61] See the following web resource for more details on metrics cited here and footnoted below: http://searchcrm.techtarget.com/answer/Metrics-ROI-IRR-NPV-payback-discounted-payback.

[62] *Simple payback* is calculated by comparing the cumulative cash investment in the program/projects and comparing it against the cumulative benefits, typically year by year in a timeline. Most programs/projects have a significant up-front investment, and then over time, this investment is recouped post deployment with benefits. Eventually, the benefits catch up to and exceed the initial and on-going investments required. The duration from initial investment to the point where the cumulative benefits exceed the costs is the *payback period*.

[63] In *Discounted payback,* the costs and benefits of the project are discounted as they occur over time to take into account the lost opportunity of investing the cash elsewhere (usually set equal to a company's cost of capital) and further by a relative measure of the projects risk (the cost of capital + a risk generated discount rate). For projects with long payback periods, discounted payback periods are more accurate at determining the real payback. As with regular payback period, making investment decisions based purely on payback period can orient the team towards quick payback projects without regard to the ultimate benefit quantity – which is best measured using NPV.

[64] *NPV* is a formula that tallies all of the net benefits of a project (benefits – costs), adjusting all results into today's currency terms. This is different than just tallying up all of the net benefits of a project over a ten-year period without discounting as the cumulative benefits without discounting overstate the overall project value, especially

institutions are the internal rate of return (IRR)[65] and return on investment (ROI) or risk-adjusted ROI.[66] Be sure to address and clearly cite the following items.]

- Financial risk, return, and impact. Two relevant categories of financial risk are ***market*** risk and ***credit*** risk. *Market* risk refers to the risk of a changing conditions in the marketplace that could impact the viability of the RE technology being deployed (for example, advances in technology that make the financed project obsolete). *Credit* risk is the risk that lenders incur by extending credit to borrowers. Lenders take on a risk that borrowers could default on payments.]

- Data sources methods, key assumptions, uncertainty, feasibility issues for each of the financial assessment metrics are described below. General assumptions applied here as well as in the rest of the impacts analysis include an inflation rate of 4% and a discount rate of 5%:

  ***Discounted net cash flow (DCF) and net present value (NPV) of implementation costs.*** The NPV of implementation costs was developed by assembling all costs and income components across the total lifetime of the plant. Although biomass plants may have a lifetime of over 25 years, the Roi-et plant was assumed to have a lifetime of 21 years equal to the EGAT power purchase agreement (PPA). The PPA calls for sale of 8.8 MW of power from the 9.95 gross MW plant (8.8 MW is the assumed total net power output).

  Total installation costs of $11.94 million US were taken from available project documentation.[67] It is assumed that this covers all plant construction, engineering, permitting, and land acquisition costs. Grid interconnection costs are covered by the Thailand central government. The plant capacity factor was not available in project documentation but is assumed to be 0.80. Fuel consumption was taken from project documentation (300 tonnes/day).[68] Fuel costs were taken as the mid-point in the range of costs estimated in a study of rice husk delivered costs in north-

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when the project has many of the investment costs up-front or in year one, and the benefits are not really kicking in until later years (where the time-value of money discounting reduces the overall value of these benefits). NPV is great at tallying up the net benefits over an investment horizon so that different projects can be compared as to the value they return to the company, but this metric alone does not highlight how long it may take to achieve the benefits (as payback period does).

[65] *IRR* is essentially the interest rate that the project can generate for the borrower, and is calculated as the discount value that when applied in the NPV formula drives the NPV formula to zero. Since IRR calculates the cash flow return for each project, investments in projects can be compared easily to other investment vehicles and to investment hurdle rates (returns vs. risks) established by the lender. But IRR is not a great indicator as to the magnitude of investment needed, benefit value or payback, so the returns may be high, but the investment high, benefits not significant and/or payback (risk) too high.

[66] ROI and risk-adjusted ROI calculates the net benefits (total benefits – total costs) of a project divided by the total costs in a ratio to help highlight the magnitude of potential returns versus costs. An ROI of 150% means that $1 invested in the project will garner the investor $1 of their original investment back + $1.50 in gains. Risk-adjusted ROI is often recommended, as it tallies using the time value of money to discount the benefits and costs over time. Risk-adjusted ROI provides a more conservative ratio, since benefits are usually higher than costs in outgoing years, thus the benefits are discounted and the calculated ratio is lower. Businesses typically expect ROI of at least 100% to usually not more than 400% (although higher is possible). The ROI formula is great at comparing the costs to benefits in a ratio, but does not highlight well the timeliness of the returns, where payback period is better.

[67] Project documentation indicates only that it is >$1.2 MM$; Roi-et Green Power Plant presentation from the Roi-et Green Power Company; http://www.jst.go.jp/asts/asts_j/files/ppt/22_ppt.pdf.

[68] "Launching Small Power Producer (SPP) employing r ice husks as fuel: A case study from Roi-et Green Power Plant"; https://pub.iges.or.jp/contents/APEIS/RISPO/inventory/db/pdf/0139.pdf.

eastern Thailand ($7.63/delivered tonne).[69] Fuel price escalation was assumed to be equal to the general inflation rate.

Other variable operations and maintenance (O&M) and fixed O&M costs were not provided in project documentation. Values for these were taken from a US publication on electricity production.[70] Annual escalation of O&M costs were also taken from the same study (2.25%/yr).

The financial structure of the project includes domestic and international grants, which were not available in project documentation. It is assumed that these apply to initial construction costs and total $1.0 million US. It is further assumed that the project developer provides 20% of the remaining implementation costs ($2.39 million) and that the financing community provides the remaining 80% ($8.55 million). The finance rate is assumed to be 10% over 20 years.

Revenue for the plant is mainly from electricity sales. Details on purchase price outlined in the PPA were not available; the price is assumed to be a constant $0.10/kWh during the plant's lifetime. The Thai national government has "special adders" or feed-in tariffs for small biomass power plants that are paid during the first 7 years of operation (about $0.01/kWh). No other renewable energy credits are assumed to be available, and neither are carbon offset credits from domestic or international programs (e.g. United Nations Clean Development Mechanism). It is possible that additional revenue from the sale of fly ash as a crop soil amendment or industrial process input could occur; however, no documentation of this was identified.

With the above inputs, a discounted net cash flow (DNCF) for the project was developed along with a discounted NPV of total implementation costs. The period of analysis covers the entire project lifetime (through 2041). The NCF analysis is done from the perspective of the project developer. This means that rather than using the total project installation costs, these costs are annualized, and that annualized stream of costs for debt service is used as one of the cash flows along with the initial equity payment and O&M costs. The sum of DNCF is calculated as:

$$\sum DNCF = E + \sum DS + \sum FOM + \sum F + \sum VOM + \sum T + \sum R_{PS} + \sum Sub + \sum R_O$$

Where all values have been discounted to 2017 US dollars:

E = initial equity payment by project developer
DS = annual debt service payment
FOM = annual fixed O&M costs
F = annual fuel costs
VOM = annual other variable O&M costs
T = annual tax payments
$R_{PS}$ = annual revenue for power sales
Sub = annual government subsidy (feed-in tariff)
$R_O$ = annual revenue from other sources (e.g. fly ash sales)

[69] Range is $6.97 to $8.29/tonne based on variability in transportation costs (transportation is 20-31% of total delivered cost); Ueasin, N. et al, "Small and very small rice husk power plant transportation network planning in Northeastern Thailand"; http://www.jyoungeconomist.com/images/stories/17_AED_ch15_pp_235_246_Nattanin.pdf.

[70] Lazard, 2016; for fixed O&M the assumption used here for biomass plants to derive a levelized cost of electricity was selected ($95/kw-yr); for other variable O&M, no value for biomass plants was provided, so the value used for coal plants was selected ($15/MWh); https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf.

Note – all cost values are negative; all revenue values are positive.

The DCF for the Roi-et Power Plant Project is shown in the table below. The sum of DCF for the project developer is shown to be $10.75 million ($2017).

The NCF analysis involves subtracting the total costs from the project revenues in each year. These annual net costs are then discounted back to $2007 using the 5% discount rate. Separate NCF estimates were calculated from the perspective of the project developer, as well as for the project overall. The difference is that the NCF for the project developer takes into account the financing assumptions on total installation costs, while the NCF for the project overall excludes these (i.e. costs in year 1 include total installation costs). The discounted NCF value reported in the summary table above is for the project developer. The financial flows are summarized in the table below.

***Risk-Adjusted Return on Investment (ROI).***

***Internal Rate of Return.***

## Financial Flows Summary: Roi-et Green Power Plant

| Year | Total Installation Costs ($) | Equity Payment ($) | Debt Service ($) | Fuel Costs ($) | Other Variable O&M ($) | Fixed O&M ($) | Taxes ($) | Power Revenue ($) | Feed-In Tariff ($) | Other Revenue ($) | Developer's Net Cash Flow ($) | Developer's Discounted NCF ($2017) | Project Discounted NCF ($2017) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2019 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2020 | $11,940,000 | $2,388,000 | $1,004,515 | $668,388 | $925,056 | $945,250 | $925,056 | $6,167,040 | $598,203 | $0 | $2,296,978 | $1,725,754 | $8,764,531 |
| 2021 | $0 | $0 | $1,004,515 | $695,124 | $945,870 | $966,518 | $925,056 | $6,167,040 | $598,203 | $0 | $2,228,161 | $1,521,864 | $2,839,787 |
| 2022 | $0 | $0 | $1,004,515 | $722,928 | $967,152 | $988,265 | $925,056 | $6,167,040 | $598,203 | $0 | $2,157,327 | $1,339,530 | $2,537,642 |
| 2023 | $0 | $0 | $1,004,515 | $751,846 | $988,913 | $1,010,501 | $925,056 | $6,167,040 | $598,203 | $0 | $2,084,413 | $1,176,597 | $2,265,789 |
| 2024 | $0 | $0 | $1,004,515 | $781,919 | $1,011,163 | $1,033,237 | $925,056 | $6,167,040 | $598,203 | $0 | $2,009,352 | $1,031,116 | $2,021,290 |
| 2025 | $0 | $0 | $1,004,515 | $813,196 | $1,033,914 | $1,056,485 | $925,056 | $6,167,040 | $598,203 | $0 | $1,932,077 | $901,328 | $1,801,487 |
| 2026 | $0 | $0 | $1,004,515 | $845,724 | $1,057,178 | $1,080,256 | $925,056 | $6,167,040 | $598,203 | $0 | $1,852,515 | $785,647 | $1,603,973 |
| 2027 | $0 | $0 | $1,004,515 | $879,553 | $1,080,964 | $1,104,562 | $925,056 | $6,167,040 | $0 | $0 | $1,172,391 | $452,007 | $1,195,940 |
| 2028 | $0 | $0 | $1,004,515 | $914,735 | $1,105,286 | $1,129,414 | $925,056 | $6,167,040 | $0 | $0 | $1,088,034 | $381,349 | $1,057,652 |
| 2029 | $0 | $0 | $1,004,515 | $951,325 | $1,130,155 | $1,154,826 | $925,056 | $6,167,040 | $0 | $0 | $1,001,164 | $319,002 | $933,822 |
| 2030 | $0 | $0 | $1,004,515 | $989,378 | $1,155,583 | $1,180,810 | $925,056 | $6,167,040 | $0 | $0 | $911,699 | $264,087 | $823,015 |
| 2031 | $0 | $0 | $1,004,515 | $1,028,953 | $1,181,584 | $1,207,378 | $925,056 | $6,167,040 | $0 | $0 | $819,555 | $215,814 | $723,931 |
| 2032 | $0 | $0 | $1,004,515 | $1,070,111 | $1,208,169 | $1,234,544 | $925,056 | $6,167,040 | $0 | $0 | $724,645 | $173,474 | $635,398 |
| 2033 | $0 | $0 | $1,004,515 | $1,112,915 | $1,235,353 | $1,262,321 | $925,056 | $6,167,040 | $0 | $0 | $626,880 | $136,427 | $556,358 |
| 2034 | $0 | $0 | $1,004,515 | $1,157,432 | $1,263,149 | $1,290,723 | $925,056 | $6,167,040 | $0 | $0 | $526,166 | $104,099 | $485,854 |
| 2035 | $0 | $0 | $1,004,515 | $1,203,729 | $1,291,569 | $1,319,764 | $925,056 | $6,167,040 | $0 | $0 | $422,406 | $75,973 | $423,024 |
| 2036 | $0 | $0 | $1,004,515 | $1,251,878 | $1,320,630 | $1,349,459 | $925,056 | $6,167,040 | $0 | $0 | $315,502 | $51,587 | $367,087 |
| 2037 | $0 | $0 | $1,004,515 | $1,301,953 | $1,350,344 | $1,379,822 | $925,056 | $6,167,040 | $0 | $0 | $205,350 | $30,524 | $317,342 |
| 2038 | $0 | $0 | $1,004,515 | $1,354,031 | $1,380,727 | $1,410,868 | $925,056 | $6,167,040 | $0 | $0 | $91,843 | $12,411 | $273,155 |
| 2039 | $0 | $0 | $1,004,515 | $1,408,193 | $1,411,793 | $1,442,613 | $925,056 | $6,167,040 | $0 | $0 | $25,129 | $3,087 | $233,953 |
| 2040 | $0 | $0 | $1,004,515 | $1,464,520 | $1,443,558 | $1,475,071 | $925,056 | $6,167,040 | $0 | $0 | $145,681 | $16,269 | $199,222 |
| 2041 | $0 | $0 | $0 | $1,523,101 | $1,476,038 | $1,508,260 | $925,056 | $6,167,040 | $0 | $0 | $734,584 | $74,579 | $168,496 |
| **Totals** | | | | | | | | | | | **$23,030,233** | **$10,753,814** | **$12,699,687** |

### D. Trading and Other Policies

[Identify any linkages to national cap and trade programs, international carbon programs, or other policies.]

- Applicability and value of any relevant carbon offsets, renewable energy credits, or other attributes derived from the option.
- Data sources methods, key assumptions, uncertainty, feasibility issues.

## Additional Impacts

[If needed, this section can include outcomes or outputs of analysis that are not included in the quantification section and the metrics it covers, and can include a more limited approach to analysis or qualitative discussion of key impacts.]

While details from project documentation were not available, the use of rice husks is expected to have significant air quality benefits. Under BAU conditions, rice husk is burned in the open causing significant local air quality impacts (e.g. fine particulate matter emissions). When used as a fuel in a modern power plant with adequate controls, emissions are reduced significantly, and the fuel is put to beneficial use. This beneficial use enhances the country's energy security, since it reduces the amount of petroleum imports required. Significant local economic benefits are also expected since money spent on electricity generated from distant plants and fuel sources is kept within the local community.

## Status of Approvals

[This reflects the status of the option as it moves through the decision making and assessment process from conception to final recommendation.]

# Attachment E. Technology Implementation Document Sample - Wind

**Rhode Island Offshore Wind Power**

This Technology Policy Implementation Document (TPID) template is used for each draft priority technology/policy option to document its status and the details of its development to support stepwise decision making and transparency needs.

*Upfront Considerations for Offshore Wind Projects in General:*

- *Initial site selection must consider the following:*
    - Wind conditions,
    - Visibility and distance to shore,
    - Proximity to power demand sites,
    - Proximity to electricity distribution systems,
    - Impact on existing shipping routes,
    - Interference with telecom installations,
    - Buried under-sea cables and gas lines,
    - Interference with aircraft flight paths,
    - Interference with bird flight paths.
- Wind power must be delivered to the electrical grid or efficiently stored. Studies of potential bottlenecks, grid connection challenges, or storage issues should be conducted.

**Option Description**

[Provide a general concept description or “overview” of the technology/policy option including its purpose and the rationale behind it and generally how it will be implemented to reach goals, including local feasibility. The “purpose” can also be thought of in terms of its intended effects and will typically fall into one of two categories: technology adoption or change in practice. The “rationale” involves mapping to objectives (e.g. sustainable development, economic vision and goals, equity, others). If the option is related to existing policies in the nation/subnational area, then this should be noted. Typical length: 1-3 paragraphs. Include a general description of the implementation model and its key mechanisms (finance, law, etc.).]

This document addresses the construction of the Block Island Wind Farm (BIWF) and Block Island Transmissions Station (BITS) for generation and transmission of offshore wind power to be supplied to residents of Block Island, Rhode Island. Offshore wind power is the use of wind farms constructed offshore, usually on the continental shelf, to harvest wind energy and generate electricity. Offshore wind is a renewable energy source that many policymakers and energy companies are considering as a way to produce low-carbon electricity at scale. Offshore wind resources tend to be stronger and steadier than onshore wind. In addition, Atlantic offshore wind resources are close to densely populated areas where electricity is needed, in contrast to the wind-swept but sparsely populated U.S. Midwest plains. Scientists estimate that U.S. offshore winds have the potential to generate hundreds of gigawatts of power. In Europe, the offshore wind industry has dramatically expanded in the last two decades as governments have subsidized this industry as part of achieving carbon emission reduction goals while providing employment opportunities.

Several federal, state, and local agencies have regulatory authority over the Project based on the location of the different Project components. The wind turbine generators (WTGs), Export Cable, and segments of the BITS will be located within Rhode Island state territorial waters. A segment of the BITS cable route is located on the OCS in federal territorial waters. The substation, upland cables, and ancillary Project facilities, such as construction and laydown staging areas, will be located onshore in the towns of New Shoreham, Narragansett, and North Kingstown in Washington County, Rhode Island.

The BIWF and BITS Project as proposed will be capable of satisfying nearly all of Block Island's energy needs and will represent approximately 1.2 percent of Rhode Island's forecasted energy demand. The project will likely displace the five existing diesel-fired generators operated by Block Island Power Company (BIPCO) that are currently used to power the Island, enhancing the electrical reliability for the Town, stabilizing the cost of electricity, and improving environmental quality by reducing air emissions from diesel generation. The need for interconnecting Block Island to the Rhode Island mainland is established by state legislation (RIGL § 39-26.1-7). The proposed Project meets these requirements by including a submarine cable system that will interconnect the Project to electrical distribution facilities on both Block Island and the Rhode Island mainland.

## Option Design and Implementation

[This section outlines the "what you do and how you do it" aspects of the option with a series of breakdowns.]

### Goals

[Specific, clearly defined, numeric metrics that address goals and objectives of the option, with explanation as needed. Goals should be expressed in units appropriate to the policy and its objectives, i.e., % of market penetration and access to technology, number of installations, quantity produced, acres affected, jobs created, risks avoided, etc. These should be achieved over and above existing and planned (business as usual or BAU levels).]

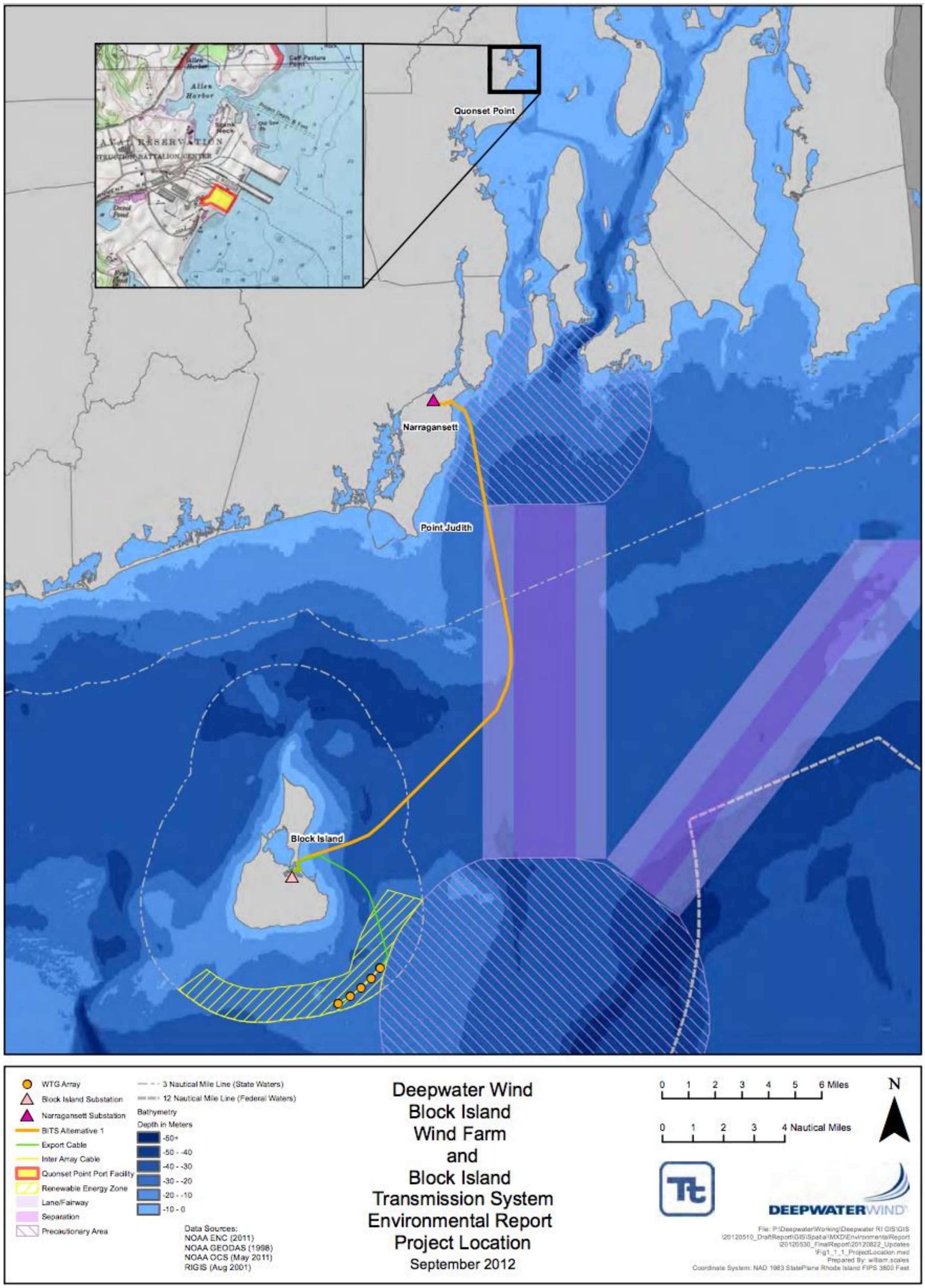
The goals of the Block Island Wind Farm (BIWF) and Block Island Transmission System (BITS) are to provide:

- Cost-effective renewable energy that utilizes wind energy;
- A nameplate capacity of no more than 30 MW and no more than 8 turbines located in state waters;
- Enhancement of the electric reliability and environmental quality of the Town of New Shoreham, Rhode Island; and
- Interconnection between Block Island and the Rhode Island mainland.

### Location

[Identify specific geographic location and scale.]

The BIFW project site is located approximately 5 km southeast of Block Island, Rhode Island and 35 km east-northeast of Montauk, New York, entirely within Rhode Island state territorial waters. The BIWF WTGs, Inter-Array Cable, and a portion of the Export Cable are located within the Rhode Island Renewable Energy Zone established by the Rhode Island Coastal Resources Management Council (CRMC). The offshore BITS cable is located in Rhode Island state territorial waters and in federal waters on the outer continental shelf (OCS). Onshore cables, the substation, switchyards and other ancillary facilities associated with the BIWF and the BITS will be located in the Towns of New Shoreham (Block Island) and Narragansett in Washington County, Rhode Island. The onshore segments of the Export Cable and the BITS on Block Island will be collocated along the same route to the BIPCO property. Construction staging and laydown for offshore construction will occur at the Quonset Point port facility in North Kingstown, also in Washington County, Rhode Island.


Quonset Point
Narragansett
Point Judith
Block Island
WTG Array
Block Island Substation
Narragansett Substation
BITS Alternative 1
Export Cable
Inter Array Cable
Quonset Point Port Facility
Renewable Energy Zone
Lane/Fairway
Separation
Precautionary Area
3 Nautical Mile Line (State Waters)
12 Nautical Mile Line (Federal Waters)
Bathymetry
Depth in Meters
-50+
-50 - -40
-40 - -30
-30 - -20
-20 - -10
-10 - 0
Data Sources:
NOAA ENC (2011)
NOAA GEODAS (1998)
NOAA OCS (May 2011)
RIGIS (Aug 2001)
Deepwater Wind
Block Island
Wind Farm
and
Block Island
Transmission System
Environmental Report
Project Location
September 2012
0 1 2 3 4 5 6 Miles
0 1 2 3 4 Nautical Miles
N
DEEPWATERWIND
File: P:\Deepwater\Working\Deepwater RI GIS\GIS
\20120510_DraftReport\GIS\Spatial\MXD\EnvironmentalReport
\20120530_FinalReport\20120822_Updates
\Fig1_1_1_ProjectLocation.mxd
Prepared By: william.scales
Coordinate System: NAD 1983 StatePlane Rhode Island FIPS 3800 Feet

**Timing**

[Identify start, ramp up, completion, and other any important timing requirements, assumptions or

The project is estimated to take approximately 6 years from project initiation to completion (full commissioning of the power station). A typical schedule for this type of project is:

- Year 1: Project initiated, tender process activated;
- Year 2: Contract award, begin site assessments,
- Year 3: Complete site assessments, begin design and permitting process;
- Year 4: Obtain permit approvals, final engineering and design, begin fabrication of turbine equipment and foundations, begin onshore construction;
- Year 5: Offshore construction begins, installation of export cables;
- Year 6: Complete construction, testing phase, final commissioning.

The anticipated schedule for construction is shown below.

**Anticipated Construction Schedule**

| Event | Dates |
|---|---|
| Contracting, mobilization, and verification | Spring 2013 – Spring 2014 |
| Onshore HDD installation | December 2013 – May 2014 |
| Cable landfall construction | January 2014 – May 2014 |
| Onshore cable installation | October 2013 – May 2014 |
| Substation construction | October 2013 – May 2014 |
| Offshore cable installation | April 2014 – August 2014 |
| Landfall demobilization and remediation | May 2014 – July 2014 |
| Foundation fabrication and transportation | October 2013 – April 2014 |
| WTG jacket installation and pile driving | April 2014 – June 2014 |
| WTG installation | June 2014 – September 2014 |
| Commissioning | July 2014 – November 2014 |

**Other**

[Use this to indicate any pertinent option design features or issues not covered above. These could be exemptions or thresholds which include or exclude involved entities.]

**Implementation Model**

[Summary description of the overall process by which the option is moved from startup to final implementation, including a diagram that shows each of the phases and the parties involved and requirements needed for each stage of decisions, including metrics in a table with supporting narrative on stepwise procedures]

**Block Island Wind Farm (BIWF) Implementation Model**

| Phase | 1 | 3 | 4 |
|---|---|---|---|
| **Phase Name** | Develop and Implement Supporting Mechanisms | Initial Site Selection and Tender Process | Public Outreach (ongoing) |
| **Parties Involved** | **Rhode Island Public Utilities Commission (PUC), State of Rhode Island** | **Rhode Island Economic Development Corporation (RIEDC), The Narragansett Electric Company (TNEC), Deepwater Wind** | **Bureau of Ocean Energy Management (BOEM), Deepwater Wind, Coastal Resources Management Commission (CRMC), RI commercial fishing interests, general public** |
| **Legal, Policy, Administrative, and Financial Mechanisms** | PUC adopts regulations for implementing Rhode Island Renewable Energy Standard (RES), state adopts long-term contracting standards for electric distribution companies.<br><br>Renewable Energy Zone (REZ), area determined to be most suitable area for offshore wind, is established. Project sited within REZ. | Local regulated utility (TNEC) solicits proposals for renewable energy project under Rhode Island Energy Independence 1 Project RFP, which indicated preferred location for a wind energy facility in "Area K" identified in RIWINDS study. Deepwater Wind chosen as contractor to develop wind project. RIEDC and Deepwater Wind enter into a Joint Development Agreement (JDA) | Deepwater Wind and other agencies invite stakeholders to series of meetings. |
| **Analytical Requirements** | RES requires 16% of retail electricity be from renewable sources by 2019.<br><br>State Legislation (RIGL § 39-26.1-7) requires the construction of a facility with "up to eight (8) wind turbines with aggregate nameplate capacity of no more than thirty (30) megawatts. | The JDA includes the requirement for the construction and operation of a demonstration-scale offshore wind energy facility located in state waters that interconnects with and supplies energy to BIPCO on Block Island and Rhode Island mainland. The proposed Project, which will sell power to TNEC under a 20-year PPA, meets these requirements of the JDA. | Public outreach program includes: employing a full-time Block Island resident to be local point of contact with office hours; meeting with local associations and citizen groups; providing regular project updates; meeting with key agencies and other potentially interested stakeholders; maintaining project website. |

| Phase | 1 | 3 | 4 |
|---|---|---|---|
| **Other Requirements** | | Meet project-specific siting criteria to minimize environmental impacts and ensure the economic and technical feasibility of the project. | |

**Block Island Wind Farm (BIWF) Implementation Model (continued)**

| Phase | 5 | 6 | 7 |
|---|---|---|---|
| **Phase Name** | Power Purchase Agreement | Feasibility and Environmental Studies | Permitting |
| **Parties Involved** | **Deepwater Wind, The Narragansett Electric Company (TNEC), National Grid plc, PUC** | **Deepwater Wind** | **Deepwater Wind, multiple permitting agencies** |
| **Legal, Policy, Administrative, and Financial Mechanisms** | Deepwater Wind execute power purchase agreements (PPA) with TNEC, a subsidiary of National Grid.<br>PUC approves PPA. | Marine surveys conducted. | Deepwater Wind submits state and federal permit applications and plans for export cabling |
| **Analytical Requirements** | Power purchase agreement pricing analysis. Price of power from BIWF capped at 24.4 cents per kWh for first full year of commercial operation. Price adjustment mechanisms; (1) the first-year price may be reduced if capital costs are lower than the amount set in the PPA; (2) the price escalates at 3.5% per year; and (3) the price is effectively reduced if the wind farm produces more power than target | Must meet multiple siting criteria to minimize environmental impacts and ensure economic and technical feasibility. | Individual permit from U.S. Army Corps of Engineers, Right-of-Way Grant from U.S. Department of Interior's Bureau of Energy Management for portion of BITS that traverses federal waters. Assent and submerged land lease from the Coastal Resources Management Commission (CRMC) |

| Phase | 5 | 6 | 7 |
|---|---|---|---|
| | amounts set in the power purchase agreement. | | |
| **Other Requirements** | | | Federal permitting agencies are also required to comply with Section 7 of the Endangered Species Act (ESA), the Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA), Section 106 of the National Historic Preservation Act (NHPA), and Section 307 of the Coastal Zone Management Act (CZMA). |

**Block Island Wind Farm (BIWF) *Implementation Model (continued)***

| Phase | 8 | 9 | 10 | 11 | 12 |
|---|---|---|---|---|---|
| **Phase Name** | Financing | Production and Procurement | Construction and Cable Installation | Testing and Commissioning | Project Scale-up |
| **Parties Involved** | **Deepwater Wind, Societe Generale, KeyBank National Association** | **Deepwater Wind, Gulf Island Fabrication, Alstom, LS Cable** | **Deepwater Wind** | **Deepwater Wind** | **Rhode Island Economic Development Corporation (RIEDC)** |
| **Legal, Policy, Administrative, and Financial Mechanisms** | Deepwater Wind secures funding of $290 million to build farm. | Gulf Island Fabrication manufactures steel jacket foundations. Alstom manufactures turbines. Export and transmission cable produced by LS Cable. | Construction of onshore and offshore equipment. Installation of cable array, undersea export cable, transmission cable. | Wind farm will become fully commissioned after 4-month testing phase and any needed repairs. | Initiate additional projects to take advantage of remaining state wind potential, based on results from early installations and the RIWINDS study. |
| **Analytical Requirements** | Financial risk analysis. | | | Testing wind turbine generators and transmission system's capabilities to meet standards for safety and grid interconnection reliability. | Prioritized list of projects based on RIWINDS study, need for power, and lack of other issues (e.g. environmental). |
| **Other Requirements** | | | | Deepwater Wind will also conduct a post-construction inspection using a multi-beam survey and shallow sub-bottom profiler (chirp) to ensure cable burial depth was achieved to verify reconstitution of the trench. Based | |

| | | | | | |
|---|---|---|---|---|---|
| | | | | upon this post-construction inspection, Deepwater Wind will determine the need and frequency of “spot-checks” during the O&M phase to ensure the minimum safe burial depth is maintained. | |

**Planning Procedures**

[identify any additional stepwise planning procedures needed to support the development of the implementation model.]

**Implementation Stages**

[Identify and describe each stage of implementation from start to finish.]

***1. Develop and Implement Supporting Mechanisms.*** Rhode Island established a renewable energy standard (RES) in 2004 that requires investor-owned utilities, including TNEC, to supply 16 percent of their retail electricity sales from renewable energy sources by 2019 (RIGL § 39-26-1 et seq.). The PUC adopted regulations for implementing the RES in 2007, which included a compliance requirement that began at 3 percent by the end of 2007. In 2009, Rhode Island also adopted a separate long-term contracting standard that requires electric distribution companies to solicit proposals and enter into long-term contracts for capacity, energy and attributes from new renewable energy facilities for up to 90 MW by 2014. The Project will sell its output to a regulated utility, TNEC, which will help to meet these requirements.

In 2006, the State of Rhode Island initiated RIWINDS to study the State's wind resource as a potential source of domestic energy supply. The goal of the program was to find means to supply 15 percent of the State's energy needs with wind-generated energy by 2012. Based on the state annualized average electricity demand of 1,000 MW, this goal amounted to 150 MW of energy, or approximately 400 MW of installed nameplate wind energy capacity due to the intermittent nature of wind energy generation. In 2007, the Rhode Island Office of Energy Resources (OER) commissioned a Phase I in Study to assess the feasibility of meeting the goal of supplying the 15 percent of the State's energy needs by constructing wind energy facilities in state and federal waters off the coast of Rhode Island. The final report concluded that 95 percent of Rhode Island's wind energy resource is located offshore (78 percent of which is located in state waters) and the quantity of existing wind resources is sufficient to meet the goal of supplying 15 percent of the State's total energy needs.

***2. Initial Site Selection and Tender Process.*** RFP #7067847, which was issued on April 3, 2008, indicated that the preferred location for a wind energy facility off the coast of Rhode Island is an area known as "Area K", located in state waters south of Block Island. Area K was determined as a preferred offshore wind energy development area in the RIWINDS siting study. The proposed Project has been sited within Area K and thus complies with the findings of the RIWINDS siting study.

Under RIGL § 39-26.1-7, TNEC was required to solicit proposals for the development of a renewable energy resource project that would not only provide a new source of renewable power but also enhance the electric reliability and environmental quality of the Town of New Shoreham, Rhode Island. Deepwater Wind responded to this request (RFP # 7067847: Rhode Island Energy Independence 1 Project) by proposing to develop both a 30 MW offshore wind farm that would interconnect directly to the Town of New Shoreham, Rhode Island on Block Island (the BIWF Project) and interconnect Block Island to the Rhode Island mainland electrical grid via a bi-directional submarine transmission cable (the BITS Project). Deepwater Wind was noticed as the successful bidder on September 25, 2008; which initiated the development of the BIWF and BITS Project.

***3. Public Outreach (ongoing).*** In 2009, Deepwater Wind began to meet with federal, state, and local officials to discuss the Project. At these meetings, Deepwater Wind provided background information on the Project including the scope, proposed environmental surveys and evaluations, and the anticipated timing of the permit applications.

During the past 3 years, Deepwater Wind has had extensive meetings with federal, state, and local representatives to describe the proposed Project and solicit early input. Deepwater Wind initiated an information exchange process prior to the formal filing of this ER and associated permit applications necessary for the approval BIWF and BITS Project. Deepwater Wind anticipates that these early sessions will lead to a more streamlined and effective permitting process for the proposed Project.

Similar information was also provided during this time period to stakeholders representing various interest groups, including the commercial and recreational fishing industry, members of the commercial shipping and recreational boating community, and non-governmental organizations (NGOs), such as the Conservation Law Foundation, the Audubon Society, The Nature Conservancy, the National Wildlife Federation, the National Resource Defense Council, Save the Bay, and The Ocean Conservancy.

Deepwater Wind has held a series of informational outreach meetings and open houses on Block Island beginning in 2009. Deepwater Wind first met with Town of New Shoreham (Block Island) elected and appointed officials immediately after execution of the JDA in January 2009. The first informational presentation to the Block Island Town Council and members of the public was held on January 21, 2009.

Deepwater Wind invited the general public to a series of public outreach meetings during the period of January to March 2009. The public outreach meetings included discussions on the Project and monitoring equipment that would be deployed on Block Island including a meteorological tower and other wind, bird, and bat monitoring equipment. Each of these meetings and their summaries were published in The Block Island Times.

Deepwater Wind also invited the general public to a series of open houses during the late spring and summer 2010 and 2011 when Block Island's seasonal population peaks. The meetings were held at public venues and community centers including the Atlantic Inn, Spring House, Dead Eye Dick's, St. Andrew's Parish Center, and Hotel Manisses. Deepwater Wind also held meetings targeted towards specific interest groups including Real Estate Brokers on March 3, 2010 and the Chamber of Commerce and Tourism Council on September 27, 2010.

In December 2011, Deepwater Wind hosted an open house in Narragansett, Rhode Island that focused on the proposed mainland route for the BITS. The open house was advertised in the local and regional newspapers.

Deepwater Wind is committed to continued stakeholder communications and effective public outreach. The public outreach program includes the following:

- Employing a full-time resident of Block Island to be the local point of contact and hosting office hours every week on Block Island, the office was opened in 2009;
- Funding a liaison to support communication with the commercial and recreational fishing community;
- Identifying and meeting with local associations, citizen groups, and other NGOs to inform them about the Project and address any issues that may be raised, for example, Deepwater Wind provides regular Project updates to the Block Island Electric Utility Task Group and the Block Island Residents Association;
- Meeting with key federal, state, and local agencies and elected officials and other potentially interested stakeholders to identify issues;
- Holding public open houses to provide information about BIWF and BITS and;
- Maintaining a Project specific web site with information on the status of the Project (http://dwwind.com). Details available on the web site include:
    - A description of the Project, including photos and visual simulations of the BIWF;

- News briefs; Contact for additional information; and
- Other appropriate Project-related information.

***4. Power Purchase Agreement.*** Deepwater Wind execute power purchase agreements (PPA) with TNEC, a subsidiary of National Grid. Price of power from BIWF will be capped at 24.4 cents per kWh for first full year of commercial operation. Price adjustment mechanisms; (1) the first-year price may be reduced if capital costs are lower than the amount set in the PPA; (2) the price escalates at 3.5% per year; and (3) the price is effectively reduced is the wind farm produces more power than target amounts set in the power purchase agreement.

***5. Feasibility Study.*** Project-specific siting criteria were applied to both minimize environmental impacts and ensure the economic and technical feasibility of the Project:

- Avoid hard substrates (e.g., cobble, boulders, bedrock) that could adversely affect Project costs and feasibility.
- Locate the WTGs in areas of the greatest wind energy potential with a minimum spacing of not less than 5 rotor-diameters (approximately 0.5 mi [805 m]) to maximize Project productivity and cost-effectiveness to enable the BIWF to maximize the "Wind Outperformance Adjustment Credit" provided for in the PPA, which benefits Rhode Island rate payers.
- Locate the WTGs as far as possible from shore while still remaining with the state waters and the Renewable Energy Zone to minimize potential visual impact to the maximum extent possible. Avoid the crossing of navigation features such as vessel traffic lanes, ferry routes, and boat racing routes to minimize potential impacts to marine uses.
- Avoid important marine habitats including hard bottom complexes (e.g., cobble, boulders) to minimize potential impacts to marine species.
- Avoid avian migration routes and foraging areas to minimize potential impact to avian species.
- Avoid cultural marine resource sites (pre-contact and post-contact).

***6. Permitting.*** Construction and operation of the BIWF and BITS will each require an Individual Permit from the U.S. Army Corps of Engineers (USACE) under Section 10 of the Rivers and Harbors Act (33 USC 403) and Section 404 of the Clean Water Act (CWA) (33 USC 1344). Prior to issuance of an Individual Permit, USACE must review the environmental effects and benefits of the Project in accordance with NEPA and other agency-specific statutes, regulations, and guidelines.

A Right-of-Way Grant (ROW Grant) from the U.S. Department of Interior's (DOI) Bureau of Ocean Energy Management (BOEM) will be necessary for the portion of the BITS that traverses federal waters. BOEM's issuance of the ROW Grant further requires review of the environmental effects and benefits of the Project in accordance with NEPA. Federal permitting agencies are also required to comply with Section 7 of the Endangered Species Act (ESA), the Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA), Section 106 of the National Historic Preservation Act (NHPA), and Section 307 of the Coastal Zone Management Act (CZMA).

At the state level, an Assent from the CRMC under the Rhode Island Coastal Resources Management Program (CRMP) is required for both the BIWF and the BITS. The CRMC Assent also constitutes federal consistency concurrence under the CZMA (16 USC 1452). A submerged lands lease from CRMC is required for the BIWF and that portion of the BITS that traverses state territorial waters. The RIDEM will review the effect of the Project on the state's water quality standards and protected species.

NEPA and implementing regulations (40 CFR 1500-1508) require that federal agencies consider the effects of their actions on the environment. Actions that are not listed as categorically excluded or considered an administrative action not subject to NEPA must be reviewed, and an Environmental

Assessment (EA) and/or an Environmental Impact Statement (EIS) must be prepared to document the analysis. Issuance of the USACE Individual Permit and BOEM ROW Grant are considered federal actions subject to NEPA review. The USACE will act as the federal Lead Agency for the NEPA review of the Project. BOEM will act as a Cooperating Agency.

Deepwater Wind has prepared this ER to support the environmental assessment under NEPA, as well as the environmental analysis required as part of other federal, state, and local permits and approvals for the Project. The scope of this ER has been established through numerous pre-application meetings with agencies and review of permit application requirements. The USACE, as the Lead Agency, will prepare a joint EA with the Cooperating Agency (BOEM) based on the information presented in this ER, input from the Cooperating Agency, and public comments in response to the notice of application for a USACE Individual Permit. The EA will be prepared in accordance with Council on Environmental Quality (CEQ) NEPA implementing regulations and agency-specific NEPA implementing regulations and guidelines. If the review indicates that the Project will not have a significant effect on the environment considering the measures taken to avoid, minimize, and mitigate impacts, the Lead and Cooperating Agency will issue a joint Finding of No Significant Impact (FONSI), thereby concluding the NEPA review.

Deepwater Wind has designed the proposed Project to comply with Rhode Island's approved CRMP. Deepwater Wind has specifically located the BIWF WTGs within the Rhode Island Renewable Energy Zone established in the RI Ocean SAMP. Deepwater Wind will submit an application to the CRMC for an Assent. Issuance of the Assent will constitute concurrence with the federal consistency certification.

***7. Financing.*** Deepwater Wind Block Island secures debt financing of $290 million from mandate lead arrangers Societe Generale of Paris, France, and KeyBank National Association of Cleveland, Ohio. In addition to its role as mandated lead arranger, Societe Generale also acts a financial advisor for debt raise, bookrunner, and administrative agent. These agreements secure all debt and equity funding needed to construct and operate BIWF. An additional $70 million in equity financing was provided by hedge fund D.E. Shaw & Co. Further details on financing were not available from the project documentation.

***8. Production and Procurement.*** Upon receipt of all requisite permits and approvals, Deepwater Wind will finalize contracts with vendors, fabrication contractors, and installation contractors. Deepwater Wind will mobilize the necessary service vessels and finalize arrangements at the Quonset Point port facilities to support Project activities. For the BIWF, Deepwater Wind will engage an independent Certified Verification Agent (CVA) to review the Project design, fabrication, and installation plans in accordance with CRMC requirements. Prior to construction, Deepwater Wind will prepare an environmental compliance plan describing all of the environmental and permitting commitments to be carried out during construction. In addition, per CRMC requirements (RI Ocean SAMP Standard 1160.8[2]), Deepwater Wind will also employ a third-party environmental inspector to monitor construction activities.

***9. Construction and Cable Installation.*** The construction of the Project involves the following sequence of activities:

- Onshore Construction
    - Substation construction
    - Underground cable installation
    - Overhead cable Installation
- Construction of cable landfalls on Block Island and the mainland
- Offshore Construction
    - Foundation fabrication and transportation

- Mobilization
- Foundation installation
- Offshore cable installation
- Installation of the WTGs

***10. Testing and Commissioning.*** Once all WTGs for the Project have been installed, Deepwater Wind will commence commissioning of the facility. This will entail testing the WTGs' and transmission system's capabilities to meet standards for safety and grid interconnection reliability. This testing will require technicians traveling to the turbines frequently during the initial operating period following construction. Technicians will be transported to and from the WTGs via a dedicated crew workboat.

After the BITS submarine cable has been installed, but before connections to the terrestrial cables are completed, Deepwater Wind will perform a conductor continuity test and a voltage test. Once connections to the terrestrial cables are complete, Deepwater Wind will perform additional commissioning tests, including a second continuity test and an AC voltage test. In addition, an optical time domain reflectometer (OTDR) will be used to verify the continuity of the fiber optic cable and that its terminations are in good working order. These testing and commissioning activities may be performed while the cable is energized.

Deepwater Wind will also conduct a post-construction inspection using a multi-beam survey and shallow sub-bottom profiler (chirp) to ensure cable burial depth was achieved to verify reconstitution of the trench. Based upon this post-construction inspection, Deepwater Wind will determine the need and frequency of "spot-checks" during the O&M phase to ensure the minimum safe burial depth is maintained.

**Parties Involved**

[Identify those affected by outcomes of the option and those involved in its implementation and their roles, including involvement in implementation mechanisms.]

***State of Rhode Island, Rhode Island Public Utilities Commission (PUC):*** implements Rhode Island Renewable Energy Standard (RES), adopts long-term contracting standards for electric distribution companies.

***The Narragansett Electric Company (TNEC), Rhode Island Economic Development Corporation (RIEDC):*** solicits proposals from contractors to develop project, TNEC enters PPA to purchase energy for the state electrical grid.

***Deepwater Wind:*** manages construction and operation of BIWF.

***Bureau of Ocean Energy Management (BOEM):*** assists with public outreach.

***Coastal Resources Management Commission (CRMC):*** assists with public outreach, also is a permitting agency.

***Societe Generale, KeyBank National Association:*** provides financing.

***Gulf Island Fabrication, Alstom, LS Cable:*** manufactures wind turbine equipment and electrical cable.

**Implementation Mechanisms**

[Identify and describe the legal, administrative, and financial mechanisms needed for implementation.

- Legal
- Policy

- Administrative
- Financial]

The need for a cost-effective renewable energy project is established by RIGL § 39-26.1-7(a) as amended by 2010 R.I. Pub. Laws 31 and 32, which require that the sale of power from a Project is "commercially reasonable." This is defined under this legislation as meaning that both the terms and pricing must be reasonably consistent with what an experienced power market analyst would expect to see for a project of a similar size, technology and location.

In its Report and Order for Docket No. 4185, the PUC noted that "the General Assembly has instructed this Commission to accept the high cost of offshore wind technology for a project with limited economies of scale, so long as the slated costs, and concomitant PPA pricing, terms and conditions, duly reflect those costs." The PUC found in their review of the Project, that the pricing met the requirement of being "commercially reasonable."

The Need for Enhancement of the Electric Reliability and Environmental Quality of the Town of New Shoreham, Rhode Island as stated in Section 1.2.1, the need for enhancing the electric reliability and environmental quality of the Town of New Shoreham, Rhode Island is established by RIGL § 39-26.1-7, The BIWF and BITS Project as proposed will be capable of satisfying nearly all of Block Island's energy needs and will represent approximately 1.2 percent of Rhode Island's forecasted generation. An Advisory Opinion prepared by the Rhode Island Department of Environmental Management (RIDEM) during the PUC review of the PPA found that the Project would provide Block Island and the region with "measurable environmental benefits". Specifically, the Project will provide an alternative energy source to the five existing diesel-fired generators operated by BIPCO that are currently used to power the Island thereby enhancing the electrical reliability for the Town as well as helping to stabilize the cost of electricity. The Project could also effectively displace the need for these generators, which could help to improve environmental quality by reducing air emissions from these sources.

The need for interconnecting Block Island to the Rhode Island mainland is established by both RIGL § 39-26.1-7 and the JDA. As stated previously in Section 1.2.1., the proposed Project meets these requirements by including a submarine cable system that will interconnect the Project to electrical distribution facilities on both Block Island and the Rhode Island mainland. Deepwater Wind has designed the proposed Project to comply with Rhode Island's approved CRMP. Deepwater Wind has specifically located the BIWF WTGs within the Rhode Island Renewable Energy Zone established in the RI Ocean SAMP. Deepwater Wind will submit an application to the CRMC for an Assent. Issuance of the Assent will constitute concurrence with the federal consistency certification. The Project is considered a Category B activity.

**Requirements**

[Identify and describe the legal, administrative, and financial requirements needed for planning and implementation, including specific metrics.

- Legal
- Policy
- Administrative
- Financial]

## Baseline Conditions

[This should also capture the relevant elements of any existing and/or planned actions at the subnational/national level that affect implementation of the option. Measures are designed to be incremental to existing and planned actions (baselines). Add information that is more detailed regards location and timing. Include a description of any existing program and the relationship to the option (for example, applicable emissions offsets, funding source).]

In 2006, the State of Rhode Island initiated RIWINDS to study the State's wind resource as a potential source of domestic energy supply. The goal of the program was to find means to supply 15 percent of the State's energy needs with wind-generated energy by 2012. Based on the state annualized average electricity demand of 1,000 MW, this goal amounted to 150 MW of energy, or approximately 400 MW of installed nameplate wind energy capacity due to the intermittent nature of wind energy generation. In 2007, the Rhode Island Office of Energy Resources (OER) commissioned a Phase I Siting Study to assess the feasibility of meeting the goal of supplying the 15 percent of the State's energy needs by constructing wind energy facilities in state and federal waters off the coast of Rhode Island. The final report concluded that 95 percent of Rhode Island's wind energy resource is located offshore (78 percent of which is located in state waters) and the quantity of existing wind resources is sufficient to meet the goal of supplying 15 percent of the State's total energy needs. The BIWF and BITS Project as proposed will be capable of satisfying nearly all of Block Island's energy needs and will represent approximately 1.2 percent of Rhode Island's forecasted generation.

The BIFW project will help the Rhode Island meet the state's Renewable Energy Standard (RES), established in June 2004. The RES requires the state's retail electricity providers, including non-regulated power producers and distribution companies, to supply 38.5% of their retail electricity sales from renewable resources by 2035. The requirement began at 3% by the end of 2007, and then increase of an additional 0.5% per year through 2010, an additional 1% per year from 2011 through 2014, and an additional 1.5% per year from 2015 through 2035. H.7413 enacted on June 2016 extended the RES to 2035, which was previously set to expire at the end of 2019.

The need for interconnecting Block Island to the Rhode Island mainland is established by both RIGL § 39-26.1-7 and the JDA. As stated previously in Section 1.2.1., the proposed Project meets these requirements by including a submarine cable system that will interconnect the Project to electrical distribution facilities on both Block Island and the Rhode Island mainland.

The Block Island Power Company (BIPCO) currently owns 5 diesel generators with production capacity of 7,275 kW that consumed 949,268 gallons of diesel fuel in 2006 to generate electricity. The State of Rhode Island consumed 7,799 GWh of electricity in 2010, and is forecasted to consume 6,371 GWh in 2020 (including efficiency improvements). Natural gas accounts for almost 97% of current electricity generation in the state.

## Metrics for Implementation Assessment

[Create a general equation followed by the procedure by which it will be customized to the technology/policy measure at broad as well as specific level through use of methods and metrics.]

### Energy and RE Technology Demand

1. Key Issues

[Describe the key issues that need to be addressed. This section addresses both energy demand as well as the market demand for the RE Technology. Reference should be made to the jurisdictional (provincial or municipal) baseline for energy demand to frame the needs for new generation at that scale (e.g. new GW of capacity needed in five year increments through 2050). The local energy demand method is described below.

Estimations of market demand for each RE Technology will be different as a result of the different players in each market. The market for a distributed generation program such as a residential solar PV program option consists of solar PV project developers (sellers) and residential households (buyers). The market for a dedicated RE power plant (e.g. biomass, large scale wind) consists of RE project developers (sellers) and the electricity authority (buyer). Therefore, the methodology for estimating market potential for distributed RE programs versus dedicated RE plants will need to be formulated accordingly]

An electric resource planning study was conducted on Block Island to determine historical of forecast energy demand. In 2006, Block Island Power Company (BIPCO) served 1,743 customers who used approximately 10.7 million kWhs of electricity.[71]

2. Methodology: Local Energy Demand

[Include general methods and metrics for the option.]

Estimate energy demand for each end use sector (residential, commercial/institutional, and industrial):

a. Begin with location-specific historical consumption for each end use sector from the relevant electricity authority:

   i. $R_d$, $CI_d$, $I_d$ - Residential, commercial/institutional, and industrial electricity demand for the historical base year (MWh). Note: further disaggregation to subsectors is also highly valuable if available (e.g. rural vs. urban residential; commercial vs. institutional; disaggregation for key electricity consumption subsectors)

***Summary of BIPCO Electricity Sales for 2006***

| ***Sector*** | ***No. of Customers*** | ***Annual MWh Sales*** |
|---|---|---|
| *Residential* | *1,300* | *4,171* |
| *Small Commercial (<1,000 KVA)* | *315* | *1,490* |
| *Large Commercial (>1,000 KVA)* | *95* | *4,172* |
| *Street/Highway Lighting* | *12* | *841* |
| *Public Authorities* | *21* | *110* |
| *Total* | *1,743* | *10,785* |

[71] Block Island Power Company, Electric Resource Planning Study. September 2007. http://www.new-shoreham.com/docs/HDR%20report%202007.pdf.

ii. For forecasting methods development, consider the provincial-level forecasting methods from the LCD Toolkit as a starting point for further refinement. These are in 2 separate memos located on iMC: one for the residential, commercial and institutional sectors; the other for the industrial sector. Higher levels of sophistication could be added to these forecasting methods to address expected changes in climate (leading to greater demands for heating or cooling); and energy price effects (e.g. elasticity of demand to future prices in electricity).

*Historical energy demand data for Block Island for 2001-2006 shows growth of 2.5% per year in total electricity sales, with 4.1% per year growth in peak summer demand.*

*Growth on Block Island follows general economic trends. Most load growth is due to new seasonally occupied residential homes and new seasonal commercial ventures, and change in usage. Expansion of commercial businesses also adds to growth. Although new building permits for single-family homes are declining, there has been an increase in remodels and additions of existing homes, some of which result in doubling the square footage for the home. The trend in larger homes with additional electrical conveniences is increasing the electrical load.*

*Electricity demand was forecast based on estimated growth and annual estimates for different types of homes developed from a review of energy usage for a sample of residential accounts:*

- *400-600 kWh for small year-round homes,*
- *600-1,400 kWh for larger year-round homes,*
- *200 kWh in off-season to 1,200 kWh in summer for small seasonal homes,*
- *400 kWh in off-season to 3,000 kWh in summer for small seasonal homes,*

*In projecting long term loads, three scenarios were developed. The “low” scenario assumed an annual growth rate of 3%, slightly lower than the historical growth of 4.1% per year in peak demand. In the second scenario, the historical rate of remodeling is assumed to continue, in addition to several new housing developments, a hotel expansion, and a grocery expansion which will include more refrigeration units. The third scenario assumes all the growth in scenario two, as well as assuming that the marina and sewer plant, which is currently have their own generators, will come off of self-generation and be served by BIPCO.*

b. Include equations for estimating local electricity demand by sector and additional details of end use. As a generic example:

i. Electricity Load Growth = ƒ (population, income growth, climate changes, technology innovation, price elasticity)

ii. Allocation of sector-based load to energy end use: % heating/cooling, lighting, cooking, water heating, remaining plug load.

iii. Diurnal profile summaries of sector-based load by season for key target years.

3. Key Metrics: Local Energy Demand

[Include specific metrics for the option, including data sources, methods, key assumptions.]

   a. Electricity and direct fuels price forecasts
   b. Elasticity of energy demand by end use sector
   c. End use technology mix and shifts (possibly, as a function of income): lights, fans, A/C, refrigeration, appliances, equipment
   d. Population, economic and income status and growth (rural versus urban breakdowns)
   e. Climate change effects on heating and cooling demand
   f. Breakdown of sector demand by end use (lighting, heating, cooling, appliances, other) and technology innovation rate impacts on consumption by end use
   g. Sector and total electricity demand diurnal load profiles (by season for key target years)
   h. Policy incentives
      i. Caps: stringency, baseline GHG intensity, flexibility, value of allowances
      ii. Other policies and requirements if/as needed

**Energy Supply**

1. Key Issues

   [Describe the key issues that need to be addressed. Summarize the jurisdictional energy supply baseline, including what new generation sources are expected to be put in place in the future under business as usual (BAU) conditions to meet future load growth. Also, how will the RE option being considered impact the BAU generation system (e.g. if it is tied to the grid or not, if it ties to a grid that serves the entire jurisdiction or to a smaller independent grid)?

   The remaining sections address the RE technology for this option.]

   BIPCO currently owns 5 diesel generators with production capacity of 7,275 kW that consumed 949,268 gallons of diesel fuel in 2006 to generate electricity.

2. Methodology: Local RE Supply

   a. Local Resource Assessment
      i. Wind monitoring at the Block Island wind project began on 25 July 2009 with the installation of a single mast, designated Mast 3813.[72] Since the wind climate can vary considerably over time scales of months to years, it is important to adjust the data collected at a site to represent historical wind conditions as closely as possible. The method typically used is to make this adjustment is

[72] Estimation of the Wind Resource of the Block Island Wind Project: http://dwwind.com/wp-content/uploads/2014/08/BIWF-Wind-Summary-Report.pdf.

known as measure-correlate-predict, or MCP. In MCP, a linear regression or other relationship is established between two or more meteorological stations. One, the target site, spans a relatively short period and the other, the reference site, spans a much longer period. The complete record of the reference stations is then applied to this relationship to estimate the long-term historical wind climate at the target site. The long-term wind resource at Mast 3813 was estimated using its daily wind speeds in a correlation with the Buzzards Bay C-MAN station. The mast's 57.4-m long-term mean wind speed is estimated to be 8.68 m/s. Using a shear exponent of 0.133, the long-term mean wind speed was estimated to be 9.08 m/s at the 80 m hub height.

ii. Observed wind density was 1.246 kg/m$^3$.

b. Supply Technology Considerations:

i. *Renewable power capacity.* The formula for calculating the power from a wind turbine is:

$$P = ½ \times C_p \times d \times A \times V^3$$

where:
*PC* = power capacity (kW)
$C_p$ = maximum power coefficient (0.24-0.45, power rating of particular turbine
*d* = air density (kg/m$^3$)
A = area swept by rotor, 3.1416*rotor length squared (m$^2$)
V= wind speed (m/s)

*ii. Renewable power production.* The general equation for renewable power production is:

$$RP = PC \times C_f \times OU_f \times 8760$$

where:
*RP* = Renewable power production (MWh/yr)
*PC* = Plant capacity (gross MW)
$C_f$ = Plant capacity factor (unitless; account for down-time by the plant for maintenance, etc.)
$OU_f$ = Plant own-use factor (unitless; fraction of gross output used on-site for plant needs; sometimes referred to as "parasitic losses")
8760 = hours per year

iii. *Power plant GHG emissions.* The will be a small amount of GHG emissions associated with the use of marine vessels to service the turbines, estimated to be 1,572 tons GHG. GHG emissions associated with construction of BIWF and BITS is estimated to be 42,000 tons.

iv. Power plant capital and operating costs:

1. Generation characteristics: 5 turbines with turbine rated power of 6 MW each. Estimated net energy production of 125 GWh/yr (capacity factor of 47.5%).

2. Installation costs: The current tally for the complete project is $360 million.
3. Operation & maintenance (O&M) costs: O&M costs are highly dependent on the distance between the project and maintenance facilities (e.g., O&M port and/or inshore assembly area) and the prevailing wind, wave, and climate conditions of the site. Offshore wind projects farther from shore and in more demanding conditions makes delivering technicians and components to the project site more difficult and costly.
4. Revenue. Price of power from BIWF capped at 24.4 cents per kWh for first full year of commercial operation. Price adjustment mechanisms; (1) the first-year price may be reduced if capital costs are lower than the amount set in the PPA; (2) the price escalates at 3.5% per year; and (3) the price is effectively reduced if the wind farm produces more power than target amounts set in the power purchase agreement.

3. <u>Key Metrics</u>
   a. Offshore Wind Technology Capital Costs: $270 million
   b. Operations & Maintenance Costs: $138/kW-yr
   c. Levelized cost of electricity (LCOE) – 45 $/MWh produced. Compare to LCOE values for other BAU generation sources. Optimally, these come from the electricity provider (EGAT); but values from the literature could be used as back-up. There are several formulas needed to convert the various units into the $/MWh units used to express levelized costs. These are briefly described below.

*Initial Investment Costs (IIC)*[73]*:* These costs are annualized to $/MWh units for each year of expected plant operation as per the formula below:

$$Annualized\ IIC = IIC * FCF * 1000 / (8760 * C_f)$$

where:
IIC = initial investment costs. These include the capital costs of land and equipment, as well as any other initial costs for planning, engineering and construction ($/kW)
$C_f$ = capacity factor (%)
8760 = hours per year
FCF = fixed charge factor[74]
1000 = conversion from $/kW to $/MW

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[73] Typically reported in units of $/kW, these costs include the total costs of construction, including land purchase, land development, permitting, interconnections, equipment, materials and all other components. Construction financing costs are also included.
[74] This factor is calculated based on assumptions regarding the plant lifetime, the effective interest rate or discount rate used to amortize capital costs, and various other factors specific to the power industry. Expressed as a decimal, typical fixed charge factors are typically between 0.10 and 0.20, meaning that the annual cost of ownership of a power generation technology is typically between 10 and 20 percent of the capital cost. Fixed charge factors decrease with longer plant lifetimes, and increase with higher discount or interest rates.

*Fixed O&M (FOM)*[75]*:* These costs are estimated for each year of plant operation in $/MWh units as per the formula below:

$$Annualized\ fixed\ O\&M\ cost = FOM * 1000 / (8760 * C_f)$$

where:
FOM = fixed O&M ($/kW-yr)
$C_f$ = capacity factor (%)
8760 = hours per year
1000 = conversion from $/kW to $/MW

*Variable O&M (VOM)*[76]*:* These costs should already be provided in units of $/MWh, so no conversion is needed.

*Fuel costs (FC):* Each year's fuel price is converted to units of $/MWh as follows:

$$Annual\ Fuel\ Cost = FP_t * HR$$

where:
$FP_t$ = fuel price in year t ($/TJ)
HR = gross heat rate (TJ/MWh)
t = year in the plant lifetime

*Discounted Costs:* All of the annual costs estimated above are then discounted as follows:

$$Discounted\ Annual\ Costs = [PV_{GEN} * DR * (1+DR)^t] / [(1 + DR)^t - 1]$$

where:
$PV_{GEN}$ = present value of the sum of all generation costs = annualized IIC + FOM + VOM + FC ($/MWh in each year of the plant's lifetime)
DR = discount rate

The values in the stream of discounted annualized costs are then levelized across the lifetime of the plant:

$$LCOE = \sum Discounted\ Annual\ Costs/PL$$

where:
LCOE = levelized cost of electricity ($/MWh)
PL = lifetime of the plant (years)

4. Project Impact:

    a. *GHG reduction from BAU:* 10,000 $tCO_2e$/yr;

[75] Typically reported in units of $/kW-yr, these costs are for those that occur on an annual basis regardless of how much the plant operates. They typically include staffing, overhead, regulatory filings, and miscellaneous direct costs.
[76] Typically reported in units of $/MWh, these costs are for those that occur on an annual basis based on how much the plant operates. They typically include costs associated with maintenance and overhauls, including repairs for forced outages, consumables such as chemicals for pollution control equipment or boiler maintenance, water use, and other environmental compliance costs.

b. *Renewable electricity production: 125,000 MWh;*

c. *Contribution toward jurisdictional target(s):* will meet 1.2 percent of Rhode Island's forecasted energy demand*;*

d. *Job creation*: 300 temporary construction jobs, 50 permanent jobs.

## Results of Assessment

[This section is where the quantification results are presented and discussed. The section begins with a standard table that presents key summarized results]

**RE Energy and Emissions Assessment Results**

| **Program/Project – Level Results** | | | | |
|---|---|---|---|---|
| **2035 RE Generation (GWh)** | **2020 - 2035 RE Generation (GWh)** | **2035 Power Demand Met (%)** | **2035 GHG Reduction ($tCO_2e$)** | **2020 – 2035 GHG Reduction ($TgCO_2e$)** |
| 125,000 | 1,875,000 | 100 | 10,000 | 150,000 |
| **Potential Jurisdictional – Level Impacts** | | | | |
| **2035 RE Generation (GWh)** | **2020 - 2035 RE Generation (GWh)** | **2035 Power Demand Met (%)** | **2035 GHG Reduction ($tCO_2e$)** | **2020 – 2035 GHG Reduction ($TgCO_2e$)** |
| | | | | |

**RE Technology Market Assessment**

| **Capacity of Resource (GW)** | **Annual Net Generation (GWh)** | **Metric C** | **Metric D** | **Metric E** |
|---|---|---|---|---|
| *Provincial (Local) Level* | | | | |
| | | | | |
| *National Scale-Up* | | | | |
| 300 | 1,800 | | | |

**Program/Project Financial Assessment**

| **Program/Project – Level Results** |
|---|

| Initial Investment Costs ($MM 2017) | NPV of Implementation Costs ($MM 2017) | Discounted Payback (Years) | Internal Rate of Return (%) | Risk-Adjusted Return on Investment (%) |
|---|---|---|---|---|
| 270 | 17 | 5 | 11 | 41 |

### A. Jurisdictional and Local Energy Supply and Demand

[This section will be completed based on the results of the demand/supply assessments, financing, and trading and other ancillary policy impacts. List the relevant metrics and results, perhaps in table to simplify, and then provide a step-wise description of the process used for evaluating metrics.]

- **Direct, Indirect, and Integrative Impacts**
  - [This section is where the summary of results for energy supply and demand provided above is documented. This also is where a link or reference to more detailed analysis and results can be found. Direct results include power generation/other energy and emissions impacts. Indirect results should either be quantified or at least qualitatively cited. These include energy and emissions impacts on upstream fuel supplies. Integrative impacts include jurisdictional level generation and emissions impacts resulting from scaling the technology up to that scale]
- **Key Uncertainties**
  - [This section addresses key uncertainties and any methods for addressing them in quantification results above.]
- **Feasibility Issues**
  - [This section addresses key feasibility issues identified and addressed or not addressed in the assessment and their implications

## Financial Flows Summary: BIWF

| Year | Total Installation Costs ($) | Equity ($) | Debt Service ($) | Fuel Costs ($) | Other Variable O&M ($) | Fixed O&M ($) | Taxes ($) | Renewable Energy Credits Revenue ($) | Net Generation (MWh) | Power Revenue ($) | Feed-In Tariff ($) | Other Revenue ($) | Developer's Net Cash Flow ($) | Developer's Discounted NCF ($2017) | Project Discounted NCF ($2017) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | 0.00 | $0 | $0 | $0 | $0 | $0 | $0.00 |
| 2019 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | | 0.00 | $0 | $0 | $0 | $0 | $0 | $0.00 |
| 2020 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | $0 | 0.00 | $0 | $0 | $0 | $0 | $0 | $0.00 |
| 2021 | ($360,000,000) | ($72,000,000) | ($20,263,990) | $0 | $0 | $0 | $0 | $0 | 0.00 | $0 | $0 | $0 | ($92,263,990) | ($75,905,813) | ($296,172,890.93) |
| 2022 | $0 | $0 | ($20,263,990) | $0 | $0 | $0 | $0 | $0 | 0.00 | $0 | $0 | $0 | ($20,263,990) | ($15,877,366) | $0.00 |
| 2023 | $0 | $0 | ($20,263,990) | $0 | $0 | ($4,425,785) | ($913,756) | $0 | 124,830 | $30,458,520 | $0 | $0 | $5,768,745 | $4,304,726 | $19,426,027.84 |
| 2024 | $0 | $0 | ($20,263,990) | $0 | $0 | ($4,525,365) | ($945,737) | $0 | 124,830 | $31,524,568 | $0 | $0 | $6,735,213 | $4,786,590 | $19,187,829.69 |
| 2025 | $0 | $0 | ($20,263,990) | $0 | $0 | ($4,627,186) | ($978,838) | $0 | 124,830 | $32,627,928 | $0 | $0 | $7,736,752 | $5,236,539 | $18,952,004.65 |
| 2026 | $0 | $0 | ($20,263,990) | $0 | $0 | ($4,731,297) | ($1,013,097) | $0 | 124,830 | $33,769,906 | $0 | $0 | $8,774,618 | $5,656,197 | $18,718,545.79 |
| 2027 | $0 | $0 | ($20,263,990) | $0 | $0 | ($4,837,752) | ($1,048,556) | $0 | 124,830 | $34,951,852 | $0 | $0 | $9,850,111 | $6,047,113 | $18,487,445.57 |
| 2028 | $0 | $0 | ($20,263,990) | $0 | $0 | ($4,946,601) | ($1,085,255) | $0 | 124,830 | $36,175,167 | $0 | $0 | $10,964,576 | $6,410,761 | $18,258,695.87 |
| 2029 | $0 | $0 | ($20,263,990) | $0 | $0 | ($5,057,899) | ($1,123,239) | $0 | 124,830 | $37,441,298 | $0 | $0 | $12,119,408 | $6,748,540 | $18,032,288.01 |
| 2030 | $0 | $0 | ($20,263,990) | $0 | $0 | ($5,171,702) | ($1,162,552) | $0 | 124,830 | $38,751,743 | $0 | $0 | $13,316,051 | $7,061,786 | $17,808,212.80 |
| 2031 | $0 | $0 | ($20,263,990) | $0 | $0 | ($5,288,065) | ($1,203,242) | $0 | 124,830 | $40,108,054 | $0 | $0 | $14,555,999 | $7,351,769 | $17,586,460.52 |
| 2032 | $0 | $0 | ($20,263,990) | $0 | $0 | ($5,407,047) | ($1,245,355) | $0 | 124,830 | $41,511,836 | $0 | $0 | $15,840,799 | $7,619,695 | $17,367,020.99 |
| 2033 | $0 | $0 | ($20,263,990) | $0 | $0 | ($5,528,706) | ($1,288,943) | $0 | 124,830 | $42,964,751 | $0 | $0 | $17,172,055 | $7,866,716 | $17,149,883.57 |
| 2034 | $0 | $0 | ($20,263,990) | $0 | $0 | ($5,653,101) | ($1,334,056) | $0 | 124,830 | $44,468,517 | $0 | $0 | $18,551,425 | $8,093,925 | $16,935,037.19 |
| 2035 | $0 | $0 | ($20,263,990) | $0 | $0 | ($5,780,296) | ($1,380,747) | $0 | 124,830 | $46,024,915 | $0 | $0 | $19,980,629 | $8,302,364 | $16,722,470.34 |
| 2036 | $0 | $0 | ($20,263,990) | $0 | $0 | ($5,910,353) | ($1,429,074) | $0 | 124,830 | $47,635,787 | $0 | $0 | $21,461,444 | $8,493,022 | $16,512,171.15 |
| 2037 | $0 | $0 | ($20,263,990) | $0 | $0 | ($6,043,336) | ($1,479,091) | $0 | 124,830 | $49,303,039 | $0 | $0 | $22,995,714 | $8,666,843 | $16,304,127.36 |
| 2038 | $0 | $0 | ($20,263,990) | $0 | $0 | ($6,179,311) | ($1,530,859) | $0 | 124,830 | $51,028,646 | $0 | $0 | $24,585,345 | $8,824,722 | $16,098,326.37 |
| 2039 | $0 | $0 | ($20,263,990) | $0 | $0 | ($6,318,345) | ($1,584,439) | $0 | 124,830 | $52,814,648 | $0 | $0 | $26,232,313 | $8,967,513 | $15,894,755.24 |
| 2040 | $0 | $0 | ($20,263,990) | $0 | $0 | ($6,460,508) | ($1,639,895) | $0 | 124,830 | $54,663,161 | $0 | $0 | $27,938,663 | $9,096,027 | $15,693,400.71 |
| 2041 | $0 | $0 | $0 | $0 | $0 | ($6,605,870) | ($1,697,291) | $0 | 124,830 | $56,576,372 | $0 | $0 | $49,970,502 | $15,494,249 | $15,494,249.22 |
| 2042 | $0 | $0 | $0 | $0 | $0 | ($6,754,502) | ($1,756,696) | | 124,830 | $58,556,545 | $0 | $0 | $51,802,043 | $15,297,287 | $15,297,286.95 |
| 2043 | $0 | $0 | $0 | $0 | $0 | ($6,906,478) | ($1,818,181) | | 124,830 | $60,606,024 | $0 | $0 | $53,699,546 | $15,102,500 | $15,102,499.79 |
| 2044 | $0 | $0 | $0 | $0 | $0 | ($7,061,874) | ($1,881,817) | | 124,830 | $62,727,235 | $0 | $0 | $55,665,361 | $14,909,873 | $14,909,873.40 |
| 2045 | $0 | $0 | $0 | $0 | $0 | ($7,220,766) | ($1,947,681) | | 124,830 | $64,922,688 | $0 | $0 | $57,701,922 | $14,719,393 | $14,719,393.19 |
| 2046 | $0 | $0 | $0 | $0 | $0 | ($7,383,233) | ($2,015,849) | | 124,830 | $67,194,982 | $0 | $0 | $59,811,749 | $14,531,044 | $14,531,044 |
| 2047 | $0 | $0 | $0 | $0 | $0 | ($7,549,356) | ($2,086,404) | | 124,830 | $69,546,806 | $0 | $0 | $61,997,451 | $14,344,812 | $14,344,812 |
| 2048 | $0 | $0 | $0 | $0 | $0 | ($7,719,216) | ($2,159,428) | | 124,830 | $71,980,945 | $0 | $0 | $64,261,728 | $14,160,681 | $14,160,681 |

### B. RE Technology Demand

[Summarize the results of the RE technology market assessment summarized in the table at the beginning of this section.] The following factors are important to understanding RE market potential for offshore wind power generation in Rhode Island: state electricity demand, in particular, the need for new baseload power for the electrical grid; available wind resources; levelized cost of electricity (LCOE) offshore wind compared to other alternatives (including fossil fuels); and financial risk analysis (see Subsection C below).

- Technical viability: e.g. equipment feasibility/maturity; wind resources; baseload demand growth for the local electrical grid.
- Local RE Market Potential

  e. Approach for assessing local RE market Potential

  Comparison of the LCOE for the technology to other alternatives with and without incentives; etc.

  f. Key Metrics

  Jurisdictional RE Market Potential (Scale-Up)

  e. Approach for assessing Jurisdictional Market Potential

  f. Key Metrics

### C. Financial Assessment

[This section will be completed based on the results of the financing assessment. The table at the front of this section will list the relevant metrics for assessing program/project financing, including financial risk. Relevant metrics[77] for option financing should include at a minimum simple payback[78], discounted payback[79] and net present value (NPV).[80] Other financial metrics

[77] See the following web resource for more details on metrics cited here and footnoted below: http://searchcrm.techtarget.com/answer/Metrics-ROI-IRR-NPV-payback-discounted-payback.

[78] *Simple payback* is calculated by comparing the cumulative cash investment in the program/projects and comparing it against the cumulative benefits, typically year by year in a timeline. Most programs/projects have a significant up-front investment, and then over time, this investment is recouped post deployment with benefits. Eventually, the benefits catch up to and exceed the initial and on-going investments required. The duration from initial investment to the point where the cumulative benefits exceed the costs is the *payback period*.

[79] In *Discounted payback,* the costs and benefits of the project are discounted as they occur over time to take into account the lost opportunity of investing the cash elsewhere (usually set equal to a company's cost of capital) and further by a relative measure of the projects risk (the cost of capital + a risk generated discount rate). For projects with long payback periods, discounted payback periods are more accurate at determining the real payback. As with regular payback period, making investment decisions based purely on payback period can orient the team towards quick payback projects without regard to the ultimate benefit quantity – which is best measured using NPV.

[80] *NPV* is a formula that tallies all of the net benefits of a project (benefits – costs), adjusting all results into today's currency terms. This is different than just tallying up all of the net benefits of a project over a ten-year period without discounting as the cumulative benefits without discounting overstate the overall

that may of interest to lending institutions are the internal rate of return (IRR)[81] and return on investment (ROI) or risk-adjusted ROI.[82] Be sure to address and clearly cite the following items.]

- Financial risk, return, and impact. Two relevant categories of financial risk are ***market*** risk and ***credit*** risk. *Market* risk refers to the risk of a changing conditions in the marketplace that could impact the viability of the RE technology being deployed (for example, advances in technology that make the financed project obsolete). *Credit* risk is the risk that lenders incur by extending credit to borrowers. Lenders take on a risk that borrowers could default on payments.]

- Data sources methods, key assumptions, uncertainty, feasibility issues for each of the financial assessment metrics are described below. General assumptions applied here as well as in the rest of the impacts analysis include an inflation rate of 4% and a discount rate of 5%:

  ***Discounted net cash flow (DCF) and net present value (NPV) of implementation costs.*** The NPV of implementation costs was developed by assembling all costs and income components across the total lifetime of the plant. The PPA calls caps electricity costs at 24.4 cents per kWh for first full year of commercial operation. The price escalates at 3.5% per year.

  Total installation costs of $270 million US based on 12,000 $/kW. It is assumed that this covers all plant construction, engineering, permitting, and land acquisition costs. The plant capacity, taken from project documentation, is 57%. Operations and maintenance (O&M) and fixed O&M costs were not provided in project documentation. A value of $138/kW-yr was taken from a US publication on wind electricity production.[83] An annual escalation of 2.25%/yr was assumed for O&M costs.

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project value, especially when the project has many of the investment costs up-front or in year one, and the benefits are not really kicking in until later years (where the time-value of money discounting reduces the overall value of these benefits). NPV is great at tallying up the net benefits over an investment horizon so that different projects can be compared as to the value they return to the company, but this metric alone does not highlight how long it may take to achieve the benefits (as payback period does).

[81] *IRR* is essentially the interest rate that the project can generate for the borrower, and is calculated as the discount value that when applied in the NPV formula drives the NPV formula to zero. Since IRR calculates the cash flow return for each project, investments in projects can be compared easily to other investment vehicles and to investment hurdle rates (returns vs. risks) established by the lender. But IRR is not a great indicator as to the magnitude of investment needed, benefit value or payback, so the returns may be high, but the investment high, benefits not significant and/or payback (risk) too high.

[82] ROI and risk-adjusted ROI calculates the net benefits (total benefits – total costs) of a project divided by the total costs in a ratio to help highlight the magnitude of potential returns versus costs. An ROI of 150% means that $1 invested in the project will garner the investor $1 of their original investment back + $1.50 in gains. Risk-adjusted ROI is often recommended, as it tallies using the time value of money to discount the benefits and costs over time. Risk-adjusted ROI provides a more conservative ratio, since benefits are usually higher than costs in outgoing years, thus the benefits are discounted and the calculated ratio is lower. Businesses typically expect ROI of at least 100% to usually not more than 400% (although higher is possible). The ROI formula is great at comparing the costs to benefits in a ratio, but does not highlight well the timeliness of the returns, where payback period is better.

[83] 2014 Wind Energy Cost Review, National Renewable Energy Laboratory, http://www.nrel.gov/docs/fy16osti/64281.pdf.

The financial structure of the project consists of private funding only, with $290 million in debt financing and another $70 million in equity financing. The finance rate is assumed to be 3.5% over 20 years.

Revenue for the plant is from electricity sales. Price of power from BIWF capped at 24.4 cents per kWh for first full year of commercial operation. The price escalates at 3.5% per year.

With the above inputs, a discounted net cash flow (DNCF) for the project was developed along with a discounted NPV of total implementation costs. The period of analysis covers the entire project lifetime (through 2041). The NCF analysis is done from the perspective of the project developer. This means that rather than using the total project installation costs, these costs are annualized, and that annualized stream of costs for debt service is used as one of the cash flows along with the initial equity payment and O&M costs. The sum of DNCF is calculated as:

$$\sum DNCF = E + \sum DS + \sum FOM + \sum F + \sum VOM + \sum T + \sum R_{PS} + \sum Sub + \sum R_O$$

Where all values have been discounted to 2017 US dollars:

E = initial equity payment by project developer
DS = annual debt service payment
FOM = annual fixed O&M costs
F = annual fuel costs
VOM = annual other variable O&M costs
T = annual tax payments
$R_{PS}$ = annual revenue for power sales
Sub = annual government subsidy (feed-in tariff)
$R_O$ = annual revenue from other sources (e.g. fly ash sales)
Note – all cost values are negative; all revenue values are positive.

The DCF for the Block Island Wind Farm Project is shown in the table below. The sum of DCF for the project developer is shown to be $156 million ($2017).

The NCF analysis involves subtracting the total costs from the project revenues in each year. These annual net costs are then discounted back to $2007 using the 5% discount rate. Separate NCF estimates were calculated from the perspective of the project developer, as well as for the project overall. The difference is that the NCF for the project developer takes into account the financing assumptions on total installation costs, while the NCF for the project overall excludes these (i.e. costs in year 1 include total installation costs). The discounted NCF value reported in the summary table above is for the project developer. The financial flows are summarized in the table below.

***Risk-Adjusted Return on Investment (ROI).***

***Internal Rate of Return.***

## D. Trading and Other Policies

[Identify any linkages to national cap and trade programs, international carbon programs, or other policies.]

- Applicability and value of any relevant carbon offsets, renewable energy credits, or other attributes derived from the option.
- Data sources methods, key assumptions, uncertainty, feasibility issues.

**Additional Impacts**

[If needed, this section can include outcomes or outputs of analysis that are not included in the quantification section and the metrics it covers, and can include a more limited approach to analysis or qualitative discussion of key impacts.]

**Status of Approvals**

[This reflects the status of the option as it moves through the decision making and assessment process from conception to final recommendation.]

**References and End Notes**

# Attachment F. Technology Implementation Document Sample – Industrial Solar

| Technology/Policy Name and Identifying Label/# |
| --- |

This Technology Policy Implementation Document (TPID) template is used for each draft priority technology/policy option to document its status and the details of its development to support stepwise decision making and transparency needs.

**Option Description**

[Provide a general concept description or "overview" of the technology/policy option including its purpose and the rationale behind it and generally how it will be implemented to reach goals, including local feasibility. The "purpose" can also be thought of in terms of its intended effects and will typically fall into one of two categories: technology adoption or change in practice. The "rationale" involves mapping to objectives (e.g. sustainable development, economic vision and goals, equity, others). If the option is related to existing policies in the nation/subnational area, then this should be noted. Typical length: 1-3 paragraphs. Include a general description of the implementation model and its key mechanisms (finance, law, etc.).]

*Upfront Considerations for Industrial power generation system utilizing solar PV technologies in the projects:*

- *Specification of End-Use Technology – this example considers small-scale roof mounted fixed position power generation plant using PV Silicon crystal based technologies to generate; deploying 1.5 MW (DC) solar panels in the Nanshan District of Shenzhen's Futian District. – systems photos are available depicting technology, power conversion, cabling, and mounting.*
- *Other technologies may include* Concentrated Solar Thermal systems (known as 'CSP'), are not the same as Photovoltaic panels used in the case study; CSP systems concentrate radiation of the sun to heat a liquid substance which is then used to drive a heat engine and drive an electric generator; and –axis and 2-axis tracking systems. Recently building and infrastructure use energy storage systems for peak shifting, spin, backup capabilities.
- *An emerging market -as technology, materials and design evolve. -is roof top installations onto buildings not designed for heavy weight loads of traditional PV solar products. Case study building structure (and roof) reinforced concrete.*
- *Input costs for Solar Power PV generation systems are nil. Ongoing operations require maintenance,, repair and monitoring, cleaning and insurance,*
- *With regard to China, time to design a roof mounted system is about 3-months; ground based systems are likely longer due to land use scarcity permitting processes and interconnect permitting process.*

*Nanshan, Shenzhen PRC*

## Option Design and Implementation

[This section outlines the “what you do and how you do it” aspects of the option with a series of breakdowns.]

*This option addresses the construction and operation of roof mounted power generation systems using fixed position silicon based PV solar technology in  Nanshan District of Shenzhen, PRC, less than 10 KM from Hong Kong. This installation uses 1.5MW-DC solar panels. The option addresses all actions needed by government, private developers, and even though the project owner self-funded the installation, we will address needs of lenders to finance similar projects. This includes city building assessments, interconnection, and land-use permits.*

*Designs for structure, electrical interconnect, and environmental matters must comply with the engineering standards. In general, the process is well developed and known*

*A power generation plant described in the case study is strongly supported be the government. The case study project was started I n2014 and benefitted from China ‘Golden Sun Program’ – rebating installers a portion of the installation cast (this incentive is no longer is available) – and power off take subsidies for both direct users and users that ‘sell’ power back to the grid.*

### Goals

[Specific, clearly defined, numeric metrics that address goals and objectives of the option, with explanation as needed. Goals should be expressed in units appropriate to the policy and its objectives, i.e., % of market penetration and access to technology, number of installations, quantity produced, acres affected, jobs created, risks avoided, etc. These should be achieved over and above existing and planned (business as usual or BAU levels).]

- *Direct use (consumption) of power generated by the PV Solar System,*
- *Start design and permitting in 2014 – with actual time six (3) months[84], and*
- *Start construction in 2014 – with actual time three (3) months*
- *System energization 2014 and remains in operation as of writing of this report.*
- *The user has since put into commission another 200 KW roof system on its building in Long Gong District, Shenzhen – for sell back to the grid - and 4.5 MW roof systems on its buildings ( a manufacturing complex)in Shiyan, Bao'an District, Shenzhen – for direct use*
- *The user is now developing projects throughout China on a build to own basis, for example a 10MW+ in Hebei Province.*

**Location**

[Identify specific geographic location and scale.]

Shenzhen, China – Nanshan District (1.5MW), Bao'an District (4.5MW), and Longgang District (200KW).

Hebei Province 10MW+

**Timing**

[Identify start, ramp up, completion, and other any important timing requirements, assumptions or concerns.]

Design and Implementation of roof mounted PV solar systems today is about 3 months and 3 months respectively. Ground mounted systems are probably longer because of land use permitting. South China is placing very high value on undeveloped and (redeveloping) lands.

PV solar panels, racking systems, cabling and power inverters can be procured locally with minimal lead times.

**Other**

[Use this to indicate any pertinent option design features or issues not covered above. These could be exemptions or thresholds that include or exclude involved entities.]

System cost – Panels, and BOS plus installation – was about 1.25 USD per watt. Today the system cost is about 0.90 USD per watt.

For planning purposes in South China solar, assume an irradiance of 1300 to 1500. Ground mount systems plan is conservatively 2 -hectors per MW.

Critical consideration when considering financing and construction include.
Business mode: business operation type such as self-use or sell-back

[84] Six months was required because of the complexities to apply for and receive the 'Golden-Sun" incentive program. Today, design and permitting is faster because the 'Golden Sun 'program no longer exists.

Construction: Building structure, land use scarcity, local power inter connections, and environmental matters such as typhoon wind and rain, high humidity, etc.

**Implementation Model**

[Summary description of the overall process by which the option is moved from startup to final implementation, including a diagram that shows each of the steps and the parties involved and requirements needed for each stage of decisions, including metrics in a table with supporting narrative on stepwise procedures.]

**Implementation Model**

| Steps | 1 | 2 | 4 |
|---|---|---|---|
| **Phase Name** | Start… | Intermediate… | Finish… |
| **Parties Involved** | Building owner and financer | EPC Contractor | Owner buy-off |
| **Legal, Policy, Administrative, and Financial Mechanisms** | Structural permit<br>Electrical Permit<br>City agreement on generation an incentive | EPC Contractor | Signed agreement generation incentive. |
| **Analytical Requirements** | Feasibility study<br>Structural report<br>Interconnection Report | Incident and noncompliance reports | Energizing |
| **If lenders** | Conditions agreed | | Conditions confirmed |

**Planning Procedures**

[identify any additional stepwise planning procedures needed to support the development of the implementation model.]

**Implementation Stages**

[Identify and describe each stage of implementation from start to finish.]

**Parties Involved**

[Identify those affected by outcomes of the option and those involved in its implementation and their roles, including involvement in implementation mechanisms.]

**Implementation Mechanisms**

[Identify and describe the legal, administrative, and financial mechanisms needed for implementation.

- Legal
- Policy
- Administrative
- Financial]

**Requirements**

[Identify and describe the legal, administrative, and financial requirements needed for planning and implementation, including specific metrics.

- Legal – permitting is smooth and understood
- Policy – *promoted area*
- Administrative
- Financial] – power purchase subsidy is available.

## Baseline Conditions

[This should also capture the relevant elements of any existing and/or planned actions at the subnational/national level that affect implementation of the option. Measures are designed to be incremental to existing and planned actions (baselines). Add information that is more detailed regards location and timing. Include a description of any existing program and the relationship to the option (for example, applicable emissions offsets, funding source).]

Businesses pay about 0.90 rmb per kwh for electricity consumption. Power buy back price is about 0.43 rmb per kwh. Incentives are similar and generally available across the country

## Metrics for Implementation Assessment

[Create a general equation followed by the procedure by which it will be customized to the technology/policy measure at broad as well as specific level through use of methods and metrics.]

**Energy Demand**

1. General Methodology

[Include general methods and metrics for the option.]

   a. Regional Long Term (RLT) Energy Demand (ED) = ƒ (regional and decadal kWh, BTU volume)
   b. Local Time and Place Specific (TPS) ED = ƒ (RLT Average +/- TPS Deviations)
      i. ED = ƒ (price and non-price attributes x volume)
         1. Price effect = ƒ (net price/payment plus elasticity)

2. Non price effect = ƒ (determinate attributes such as guarantees, co-benefits, plus elasticity)
3. Volume = ƒ (end use technology, current level of need, growth, flexibility, net import/export

ii. Volume/Load Growth = ƒ (population, economic and income growth, climate changes, technology innovation, policy incentives (e.g. caps), financial incentives

1. End use technology = ƒ (lights, fans, A/C, refrigeration, appliances, equipment)
2. Policy effects
    a. Cap effect = ƒ (stringency, baseline GHG intensity, flexibility (e.g. offsets, excess allowance purchase), value of allowances
    b. REC effect = ƒ (stringency, flexibility, value of credits)
3. Financial incentives supply = ƒ (return, risk, impact)
4. Net import/export = ƒ (on site generation vs. total consumption)

2. Key Methods

[Include specific methods for the option.]

i. RLT ED calculation

1. Overall methods and metrics
2. Disaggregation parameters:
    a. Drivers for time based variation adjustments
    b. Drivers for location based variation adjustments

ii. TPS ED deviations

1. Adjustment methods and metrics
    a. Time based variation adjustments
    b. Location based variation adjustments

3. Key Metrics

[Include specific metrics for the option, including data sources, methods, key assumptions.]

a. Electricity input cost
b. Incentive rate per kwh
c. Installation subsidies (no longer available)
d. Local utility power buy-back price
e. Building power profile

f. Financial incentives:

   i. Risk: governance, market, project

   ii. Return: NPV, rate, payback period, level, liquidity

g. On site generation level and growth

h. Generally, in China – tax credits and accelerated depreciation treatments are not viable.

**Energy Supply**

1. Current market rate is 0.90 rmb per kwh
2. Power stability

**Results of Assessment**

[This section is where the quantification results are presented and discussed.]

**A. RLT and TPS Energy Demand**

[This section will be completed based on the results of the demand/supply assessments, financing, and trading and other ancillary policy impacts. List the relevant metrics and results, perhaps in table to simplify, and then provide a step-wise description of the process used for evaluating metrics.]

- **Direct, Indirect, and Integrative Impacts**
  - The builder –owner chose not to finance the installation. A case was run using 30% of total cost as sponsor equity. Primary factor for investment is time to payback.
- **Data Sources**
  - Prior history from local installations, led by NREL data, and equipment manufacture reliability. Summit View has used reliability and investment readiness reports form bank.
- **Quantification Methods and Tool**
  - SAAS tools are available to access equipment performance and local solar irradiance
  - Local installation information is traded among suppliers
  - TUV and State of California data sets for equipment supplier certification confirmation
- **Key Assumptions**
  - Energy prices from last six months are known as a base line. Tie –in with local, provincial and state government on expectations and environmental matters.
- **Key Uncertainties**

  - Sustainability of power purchase incentives
  - Reliability of equipment suppliers technical and financially.
- **Feasibility Issues**
  - none, demonstrated history
  - Issues may arise selecting ne or advanced tech.

**B. RLT and TPS Energy Supply**

[Use the same template as for Energy Demand, above.]

- Direct, indirect, and integrative effects for key metrics
- Data sources methods, key assumptions, uncertainty, feasibility issues

**C. Financial Incentives**

[Use the same template as for Energy Demand, above.]

- Government provides rebate per kWh for installed solar systems.
- Direct, indirect, and integrative effects including risk, return, and impact
- Data sources methods, key assumptions, uncertainty, feasibility issues

**D. Trading and Other Policies**

[Use the same template as for Energy Demand, above.] – requires further study on carbon offset and trading

- Direct, indirect, and integrative effects including stringency, flexibility, and values
- Data sources methods, key assumptions, uncertainty, feasibility issues

**Additional Impacts**

[If needed, this section can include outcomes or outputs of analysis that are not included in the quantification section and the metrics it covers, and can include a more limited approach to analysis or qualitative discussion of key impacts.]

None

**Status of Approvals**

[This reflects the status of the option as it moves through the decision-making and assessment process from conception to final recommendation.]

Project is complete/operational. No surprises. Owner continues to make substantial investment in solar power generation capacity.

FINANCIAL SUMMARY ASSUMING 30% SPONSOR EQUITY – 2. 1 YEAR PAYBACK

# SOLAR ARRAY PROFORMA - CCS INDUSTRIAL SOLAR CASE STUDY

**Leveraged Investment Case**
Annual Price Escalation Method

## SYSTEM DESCRIPTION

| | |
|---|---|
| **Power W(DC)** | 1,500,000 |
| **Production (k-Wh)** | 1,800,000 |
| Installed Cost Per Watt (DC) | 6.21 RMB (exclusive of VAT) |
| Other Costs e.g. Fees, PPA Contract, etc | 0.00 million RMB |

## POWER RATES

| | |
|---|---|
| Description | Market Based Pricing |
| Power Purchase per k-Wh (RMB) | 1.32 |
| Escalation Rate per Year | 2.0% |

| Levelized cost | |
|---|---|
| 5 years | 1.37 RMB |
| 10 years | 1.44 RMB |
| 15 years | 1.52 RMB |
| 20 years | 1.60 RMB |

## CAPITAL

| | | |
|---|---|---|
| Investment | 2.79 | 30.0% |
| Debt (see note *) | 6.00 | 70.0% |
| **Total** | 8.79 | million |

## FINANCIAL PERFORMANCE

| Term | **20 - Years** | | **15 - Years** | |
|---|---|---|---|---|
| Internal Rate of Return - Sponsor Equity | 48.6% | | 48.4% | |
| Principle Payback | 2.1 - years | | 2.1 - years | |
| Cash Flow Year One | 1.329 | | 1.329 | |
| EBITDA | 49.59 | | 35.86 | |
| NPV @ 8% | 17.45 | | 14.00 | |
| Cash Flow | 40.51 | 14.49 X | 26.78 | 9.58 X |
| Interest Paid on Debt | 2.56 | | 2.56 | |

## NOTES:

| | |
|---|---|
| Exchange Rate | 6.9 as of June 19, 2017 |
| Inflation Rate | 3.0% |
| * Debt Interest Rate | 7.0% |
| * Debt term | 10 - Years |

Currency - Chinese Yuan (RMB) - millions)

Note: This is an estimate of the investment being considered. It may change for when the final engineering estimate is provided and for factors outside the control of the this group. Any decision to make this investment should follow a detailed engineering and site review.

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## SOLAR ARRAY PROFORMA - CCS INDUSTRIAL SOLAR CASE STUDY

| System Price | Capital | IRR | NPV@8% | Payback | Cash Flow | EBITDA | Interest | Principle | Debt |
|---|---|---|---|---|---|---|---|---|---|
| per-watt | RMB (million) | 15-years | 15-years | years | 15-years | 20-years | full term | Sponsor | |
| 6.21 | 8.79 | 48.4% | 14.00 | 2.14 | 26.78 | 35.86 | 2.56 | 2.79 | 6.00 |
| 9.00 | 13.05 | 25.6% | 11.28 | 4.38 | 22.69 | 35.86 | 3.72 | 4.05 | 9.00 |
| 8.55 | 11.85 | 28.2% | 11.72 | 3.91 | 23.35 | 35.86 | 3.53 | 3.85 | 8.00 |
| 8.10 | 11.65 | 31.1% | 12.16 | 3.49 | 24.01 | 35.86 | 3.35 | 3.65 | 8.00 |
| 7.65 | 11.44 | 34.4% | 12.60 | 3.11 | 24.67 | 35.86 | 3.16 | 3.44 | 8.00 |
| 7.20 | 10.24 | 38.1% | 13.04 | 2.77 | 25.33 | 35.86 | 2.97 | 3.24 | 7.00 |
| 6.75 | 10.04 | 42.4% | 13.48 | 2.47 | 25.99 | 35.86 | 2.79 | 3.04 | 7.00 |
| 6.30 | 8.84 | 47.4% | 13.91 | 2.19 | 26.64 | 35.86 | 2.60 | 2.84 | 6.00 |
| 5.85 | 8.63 | 53.1% | 14.35 | 1.94 | 27.30 | 35.86 | 2.42 | 2.63 | 6.00 |

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## SOLAR ARRAY PROFORMA - CCS INDUSTRIAL SOLAR CASE STUDY

| Electricty Price | Equipment Price | IRR | NPV@8% | Payback | Cash Flow | EBITDA | Interest | Principle | Debt |
|---|---|---|---|---|---|---|---|---|---|
| per-watt | per watt | 15-years | 15-years | years | 15-years | 20-years | full term | Sponsor | |
| 1.320 | 6.210 | 0.484 | 14.002 | 2.137 | 26.776 | 35.860 | 2.565 | 2.795 | 6.000 |
| 1.584 | 6.210 | 0.637 | 18.014 | 1.599 | 33.948 | 43.032 | 2.565 | 2.795 | 6.000 |
| 1.452 | 6.210 | 0.729 | 20.421 | 1.389 | 38.251 | 47.336 | 2.565 | 2.795 | 6.000 |
| 1.320 | 6.210 | 0.729 | 20.421 | 1.389 | 38.251 | 47.336 | 2.565 | 2.795 | 6.000 |
| 1.188 | 6.210 | 0.627 | 17.773 | 1.624 | 33.517 | 42.602 | 2.565 | 2.795 | 6.000 |
| 1.056 | 6.210 | 0.447 | 13.007 | 2.329 | 24.997 | 34.082 | 2.565 | 2.795 | 6.000 |
| 0.924 | 6.210 | 0.238 | 7.287 | 4.774 | 14.773 | 23.857 | 2.565 | 2.795 | 6.000 |
| 0.792 | 6.210 | 0.050 | 1.973 | 12.659 | 5.230 | 14.314 | 2.565 | 2.795 | 6.000 |
| 0.660 | 6.210 | -0.041 | 0.530 | 17.304 | 1.555 | 7.157 | 2.565 | 2.795 | 6.000 |
| 0.528 | 6.210 | -0.101 | 0.212 | 0.000 | 0.622 | 2.863 | 2.565 | 2.795 | 6.000 |

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| Year of Operation | | 1 | 2 | 3 | 4 | 5 | 10 | 15 | 20 |
|---|---|---|---|---|---|---|---|---|---|
| **System Sales** | | | | | | | | | |
| Capacity (Megawatts per year) | | 1.500 | 1.493 | 1.485 | 1.478 | 1.470 | 1.434 | 1.398 | 1.364 |
| Degradation | | 0.50% | | | | | | | |
| **Total 000 Mwh per year** | | **1.800** | **1.791** | **1.782** | **1.773** | **1.764** | **1.721** | **1.678** | **1.636** |
| Annual Rate Escallation | | 2.00% | | | | | | | |
| Power Cost per kw-h | | 1.320 | 1.346 | 1.373 | 1.401 | 1.429 | 1.578 | 1.742 | 1.923 |
| **Revenue from Power Sales (M)** | | **2.376** | **2.411** | **2.447** | **2.484** | **2.521** | **2.714** | **2.923** | **3.147** |
| **cummulative revenue** | | 2.376 | 4.787 | 7.235 | 9.719 | 12.239 | 25.418 | 39.608 | 54.888 |
| **Total Revenue** | | **2.376** | **2.411** | **2.447** | **2.484** | **2.521** | **2.714** | **2.923** | **3.147** |
| *Revenue per kw-h* | | 1.320 | 1.346 | 1.373 | 1.401 | 1.429 | 1.578 | 1.742 | 1.923 |
| **Cost & Expense** | | | | | | | | | |
| Property lease per year | 0.00% | - | - | - | - | - | - | - | - |
| O&M expense | 4.00% | 0.095 | 0.098 | 0.101 | 0.104 | 0.107 | 0.124 | 0.144 | 0.167 |
| Insurance (% revenue) | 5.00% | 0.119 | 0.121 | 0.122 | 0.124 | 0.126 | 0.136 | 0.146 | 0.157 |
| Other Fees - Community Support | | - | - | - | - | - | - | - | - |
| Depreciation | SIMPLE | 0.932 | 0.932 | 0.932 | 0.932 | 0.932 | 0.932 | - | - |
| Extended Cost | | 1.145 | 1.150 | 1.155 | 1.160 | 1.165 | 1.191 | 0.290 | 0.324 |
| Cost per kw-h | | 0.636 | 0.642 | 0.648 | 0.654 | 0.660 | 0.692 | 0.173 | 0.198 |
| **Total Extended Cost** | | **1.145** | **1.150** | **1.155** | **1.160** | **1.165** | **1.191** | **0.290** | **0.324** |
| **Total Cost per kw-h** | | 0.636 | 0.642 | 0.648 | 0.654 | 0.660 | 0.692 | 0.173 | 0.198 |
| **Gross Operating Profit** | | **1.231** | **1.261** | **1.293** | **1.324** | **1.356** | **1.523** | **2.633** | **2.823** |
| *% GOP* | | *0.518* | *0.523* | *0.528* | *0.533* | *0.538* | *0.561* | *0.901* | *0.897* |
| *cummulative GOP* | | *1.231* | *2.492* | *3.785* | *5.109* | *6.465* | *13.743* | *26.545* | *40.275* |

**SOLAR ARRAY PROFORMA - CCS INDUSTRIAL SOLAR CASE STUDY** **Version: 1** **Date: 20170619**

| INCOME | | 1 | 2 | 3 | 4 | 5 | 10 | 15 | 20 |
|---|---|---|---|---|---|---|---|---|---|
| Revenue | | 2.376 | 2.411 | 2.447 | 2.484 | 2.521 | 2.714 | 2.923 | 3.147 |
| *Revenue per kwh* | | *1.320* | *1.346* | *1.373* | *1.401* | *1.429* | *1.578* | *1.742* | *1.923* |
| Cost | | 1.145 | 1.150 | 1.155 | 1.160 | 1.165 | 1.191 | 0.290 | 0.324 |
| Gross Operating Profit | | 1.231 | 1.261 | 1.293 | 1.324 | 1.356 | 1.523 | 2.633 | 2.823 |
| *GOP per kwh* | | *0.684* | *0.704* | *0.725* | *0.747* | *0.769* | *0.885* | *1.569* | *1.725* |
| ST Interest Payment | | - | | | | | | | |
| LT Interest Payment | | 0.41 | 0.41 | 0.37 | 0.34 | 0.29 | 0.04 | - | - |
| Development Expense | | - | - | - | - | - | | | |
| Deferred development | | - | - | - | - | - | - | - | - |
| Interest Income | 0.00% | - | - | - | - | - | - | - | - |
| other | | | | | | | | | |
| NEBT | | 0.82 | 0.85 | 0.92 | 0.99 | 1.06 | 1.48 | 2.63 | 2.82 |
| cum NEBT | | 0.82 | 1.68 | 2.59 | 3.58 | 4.64 | 11.18 | 23.98 | 37.71 |
| Tax | **0.0%** | - | - | - | - | - | - | - | - |
| Net | | 0.82 | 0.85 | 0.92 | 0.99 | 1.06 | 1.48 | 2.63 | 2.82 |
| % Revenue | | 34.7% | 35.3% | 37.5% | 39.8% | 42.1% | 54.7% | 90.1% | 89.7% |
| other Non Operating Profit | | - | - | - | - | - | - | - | - |
| Income | | 0.82 | 0.85 | 0.92 | 0.99 | 1.06 | 1.48 | 2.63 | 2.82 |

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| SOURCE & USE | Beginning | 1 | 2 | 3 | 4 | 5 | 10 | 15 | 20 |
|---|---|---|---|---|---|---|---|---|---|
| **Beginning Cash** | | **-** | **1.329** | **2.614** | **3.929** | **5.277** | **12.502** | **24.143** | **37.682** |
| Revenue | | 2.376 | 2.411 | 2.447 | 2.484 | 2.521 | 2.714 | 2.923 | 3.147 |
| Investment Grants | | - | | | | | | | |
| Energy Tax Credit | | - | - | - | - | - | | | |
| Investment | 2.795 | | | | | | | | |
| Debt | 6.521 | | | | | | | | |
| Interest Income | | - | - | - | - | - | - | - | - |
| Depreciation Credits | | - | | | | | | | |
| **Cash Source** | **9.315** | **2.376** | **2.411** | **2.447** | **2.484** | **2.521** | **2.714** | **2.923** | **3.147** |
| EPC | 9.315 | | | | | | | | |
| Development & other | | - | - | - | - | - | | | |
| Expense | | 0.214 | 0.218 | 0.223 | 0.228 | 0.233 | 0.260 | 0.290 | 0.324 |
| Deferred development | | - | - | - | - | - | - | - | - |
| Interest | | 0.406 | 0.411 | 0.375 | 0.336 | 0.295 | 0.039 | - | - |
| Principle | | 0.427 | 0.498 | 0.534 | 0.572 | 0.614 | 0.870 | - | - |
| Other | | - | - | - | - | - | - | - | - |
| sub-total Cash Use | 9.315 | 1.047 | 1.127 | 1.132 | 1.137 | 1.142 | 1.168 | 0.290 | 0.324 |
| Estimated Tax | | - | - | - | - | - | - | - | - |
| **Cash Use** | | **1.047** | **1.127** | **1.132** | **1.137** | **1.142** | **1.168** | **0.290** | **0.324** |
| Disbursement | **No** | - | - | - | - | - | - | - | - |
| **Net** | - | 1.329 | 1.284 | 1.316 | 1.347 | 1.379 | 1.546 | 2.633 | 2.823 |
| **Ending Cash** | **-** | **1.329** | **2.614** | **3.929** | **5.277** | **6.656** | **14.048** | **26.776** | **40.505** |

**SOLAR ARRAY PROFORMA - CCS INDUSTRIAL SOLAR CASE STUDY** **Version: 1** **Date: 20170619**

| CASH FLOW | Beginning | 1 | 2 | 3 | 4 | 5 | 10 | 15 | 20 |
|---|---|---|---|---|---|---|---|---|---|
| Opening Cash | 9.315 | - | 1.329 | 2.614 | 3.929 | 5.277 | 12.502 | 24.143 | 37.682 |
| Operating Net Income | | 0.825 | 0.851 | 0.918 | 0.988 | 1.061 | 1.484 | 2.633 | 2.823 |
| Grants & other | | - | | | | | | | |
| Depreciation | **SIMPLE** | 0.932 | 0.932 | 0.932 | 0.932 | 0.932 | 0.932 | - | - |
| EPC | 9.315 | - | - | - | - | - | - | - | - |
| ST Principle Payment | | - | | | | | | | |
| LT Principle Payment | | 0.427 | 0.498 | 0.534 | 0.572 | 0.614 | 0.870 | - | - |
| Cash Flow | | 1.329 | 1.284 | 1.316 | 1.347 | 1.379 | 1.546 | 2.633 | 2.823 |
| Ending Cash | - | 1.329 | 2.614 | 3.929 | 5.277 | 6.656 | 14.048 | 26.776 | 40.505 |
| Debt Reserve Compliance | - | OK | OK | OK | OK | OK | OK | | |
| EBITDA | | 2.162 | 2.193 | 2.224 | 2.256 | 2.288 | 2.455 | 2.633 | 2.823 |
| EBITDA per Revenue | | 0.910 | 0.909 | 0.909 | 0.908 | 0.908 | 0.904 | 0.901 | 0.897 |
| EBITDA per kw-h | | 1.201 | 1.224 | 1.248 | 1.272 | 1.297 | 1.427 | 1.569 | 1.725 |
| Estimated Cost per kw-h | | 0.119 | 0.122 | 0.125 | 0.129 | 0.132 | 0.151 | 0.173 | 0.198 |

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| BALANCE SHEET | | 1 | 2 | 3 | 4 | 5 | 10 | 15 | 20 |
|---|---|---|---|---|---|---|---|---|---|
| Cash | | 1.329 | 2.614 | 3.929 | 5.277 | 6.656 | 14.048 | 26.776 | 40.505 |
| Gross Assets | | 9.315 | 9.315 | 9.315 | 9.315 | 9.315 | 9.315 | 9.315 | 9.315 |
| cum Depreciation | SIMPLE | 0.932 | 1.863 | 2.795 | 3.726 | 4.658 | 9.315 | 9.315 | 9.315 |
| Net Plant & Equipment | | 8.384 | 7.452 | 6.521 | 5.589 | 4.658 | - | - | - |
| **Total Assets** | | **9.713** | **10.066** | **10.450** | **10.866** | **11.313** | **14.048** | **26.776** | **40.505** |
| **Debt** | | **6.094** | **5.596** | **5.062** | **4.490** | **3.877** | **0.075** | **0.000** | **0.000** |
| Paid In Capital | | 2.795 | 2.795 | 2.795 | 2.795 | 2.795 | 2.795 | 2.795 | 2.795 |
| Retained Earnings | | 0.825 | 1.675 | 2.593 | 3.581 | 4.642 | 11.179 | 23.981 | 37.710 |
| **Total Equity** | | **3.619** | **4.470** | **5.388** | **6.376** | **7.437** | **13.973** | **26.775** | **40.505** |
| Debt & Equity | | **9.713** | **10.066** | **10.450** | **10.866** | **11.313** | **14.048** | **26.776** | **40.505** |
| check | | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

**SOLAR ARRAY PROFORMA - CCS INDUSTRIAL SOLAR CASE STUDY** **Version: 1** **Date: 20170619**

| HIGHLIGHTS | | 1 | 2 | 3 | 4 | 5 | 10 | 15 | 20 |
|---|---|---|---|---|---|---|---|---|---|
| **Valuation** | | | | | | | | | |
| Net Present Value @8% | | $23.509 | | Price / FCF (Year 20) | 0 | | | | |
| IRR EBITDA | | 24.2% | | | | | | | |
| Return on Investment (levered) | | 48.6% | | Debt to Equity | 2.33 X | | | | |
| **Management** | | | | | | | | | |
| Return on Assets | | 8.5% | 8.5% | 8.8% | 9.1% | 9.4% | 10.6% | 9.8% | 7.0% |
| Return on Equity | | 22.8% | 19.0% | 17.0% | 15.5% | 14.3% | 10.6% | 9.8% | 7.0% |
| **Annualized Electricity Cost** | | 9.935 | 0.629 | 0.598 | 0.564 | 0.528 | 0.298 | 0.290 | 0.324 |
| Electricity (000 kwH) | | 1.800 | 1.791 | 1.782 | 1.773 | 1.764 | 1.721 | 1.678 | 1.636 |
| Per KwH | | 5.519 | 0.351 | 0.336 | 0.318 | 0.299 | 0.173 | 0.173 | 0.198 |
| LCOEper kwH @ | 8.0% | 0.761 | | | | | | | |
| **Income** | | | | | | | | | |
| Revenue | | 2.376 | 2.411 | 2.447 | 2.484 | 2.521 | 2.714 | 2.923 | 3.147 |
| Net Income (before subsidy) | | 0.825 | 0.851 | 0.918 | 0.988 | 1.061 | 1.484 | 2.633 | 2.823 |
| Net Income/Rev | | 34.7% | 35.3% | 37.5% | 39.8% | 42.1% | 54.7% | 90.1% | 89.7% |
| EBITDA | (9.315) | 2.162 | 2.193 | 2.224 | 2.256 | 2.288 | 2.455 | 2.633 | 2.823 |
| EBITDA/kw-h | | 1.201 | 1.224 | 1.248 | 1.272 | 1.297 | 1.427 | 1.569 | 1.725 |
| **EBITDA to Revenue** | | **91.0%** | **90.9%** | **90.9%** | **90.8%** | **90.8%** | **90.4%** | **90.1%** | **89.7%** |
| **Cash** | | | | | | | | | |
| Free Cash Flow -ops | (9.315) | 2.162 | 2.193 | 2.224 | 2.256 | 2.288 | 2.455 | 2.633 | 2.823 |
| Interest,principle and tax | | 0.833 | 0.909 | 0.909 | 0.909 | 0.909 | 0.909 | - | - |
| Sub-total | (2.795) | 1.329 | 1.284 | 1.316 | 1.347 | 1.379 | 1.546 | 2.633 | 2.823 |
| other | | - | - | - | - | - | - | - | - |
| Net | (2.795) | 1.329 | 1.284 | 1.316 | 1.347 | 1.379 | 1.546 | 2.633 | 2.823 |
| **Cash to Revenue** | | **0.559** | **0.533** | **0.538** | **0.542** | **0.547** | **0.570** | **0.901** | **0.897** |
| **Per Kilowatt-Hour** | | | | | | | | | |
| Revenue per kw-h | | 1.320 | 1.346 | 1.373 | 1.401 | 1.429 | 1.578 | 1.742 | 1.923 |
| Opex per kw-h | | 0.636 | 0.642 | 0.648 | 0.654 | 0.660 | 0.692 | 0.173 | 0.198 |
| Development per kw-h | | - | - | - | - | - | | | - |
| Gross Operating Profit | | 0.684 | 0.704 | 0.725 | 0.747 | 0.769 | 2.270 | 1.914 | 2.121 |

**SOLAR ARRAY PROFORMA - CCS INDUSTRIAL SOLAR CASE STUDY** **Version: 1** **Date: 20170619**

FINANCIAL PROFORMA – NO DEBT, 100% SPONOSR EQUITY USED

# SOLAR ARRAY PROFORMA - CCS INDUSTRIAL SOLAR CASE STUDY

**Non Leveraged Investment Case**
Annual Price Escalation Method

## SYSTEM DESCRIPTION

| | |
|---|---|
| **Power W(DC)** | 1,500,000 |
| **Production (k-Wh)** | 1,800,000 |

| | |
|---|---|
| Installed Cost Per Watt (DC) | 6.21 RMB (exclusive of VAT) |
| Other Costs e.g. Fees, PPA Contract, etc | 0.00 million RMB |

## POWER RATES

| | |
|---|---|
| Description | Market Based Pricing |
| Power Purchase per k-Wh (RMB) | 1.32 |
| Escalation Rate per Year | 2.0% |

| **Levelized cost** | |
|---|---|
| 5 years | 1.37 RMB |
| 10 years | 1.44 RMB |
| 15 years | 1.52 RMB |
| 20 years | 1.60 RMB |

## CAPITAL

| | | |
|---|---|---|
| Investment | 9.31 | 99.9% |
| Debt (see note *) | 0.00 | 0.1% |
| **Total** | 9.31 | million |

## FINANCIAL PERFORMANCE

| Term | **20 - Years** | | **15 - Years** | |
|---|---|---|---|---|
| Internal Rate of Return - Sponsor Equity | 24.2% | | 23.4% | |
| Principle Payback | 4.2 | - years | 4.2 | - years |
| Cash Flow Year One | 2.161 | | 2.161 | |
| EBITDA | 49.59 | | 35.86 | |
| NPV @ 8% | 23.50 | | 20.05 | |
| Cash Flow | 49.58 | 5.33 X | 35.85 | 3.85 X |
| Interest Paid on Debt | 0.00 | | 0.00 | |

## NOTES:

| | |
|---|---|
| Exchange Rate | 6.9 as of June 19, 2017 |
| Inflation Rate | 3.0% |
| * Debt Interest Rate | Does Not Apply |
| * Debt term | Zero - Years |

Currency - Chinese Yuan (RMB) - millions)

Note: This is an estimate of the investment being considered. It may change for when the final engineering estimate is provided and for factors outside the control of the this group. Any decision to make this investment should follow a detailed engineering and site review.

**Date: 20170619** **Version: 1** **Confidential**

# Attachment G. Technology Implementation Document Sample - Hydro

## Nepal Micro-Hydroelectric Distributed Power

[This Technology Policy Implementation Document (TPID) template is used for each draft priority technology/policy option to document its status and the details of its development to support stepwise decision making and transparency needs.]

*Upfront Considerations for Micro-Hydro Power Projects:*

- Does the terrain provide sufficient elevation change to allow for sufficient head (vertical distance of water fall) and is there sufficient water flow in the target location?
- Does historical precipitation records and expected climate patterns provide confidence that the resource is stable for at least the life of the project?
- Type of grid created by micro-hydro systems; village mini-grids or connection to local or national grid.
- Electricity storage requirements to deal with temporal fluctuations in demand.
- Current grid-connection status of target population; Will the renewable energy replace fossil fuel generated grid energy or direct fuel use, such as kerosene lighting and small diesel generators?
- Possible changes in demand patterns for populations that were not previously grid-connected; Will there be expanded power demand after electrification?

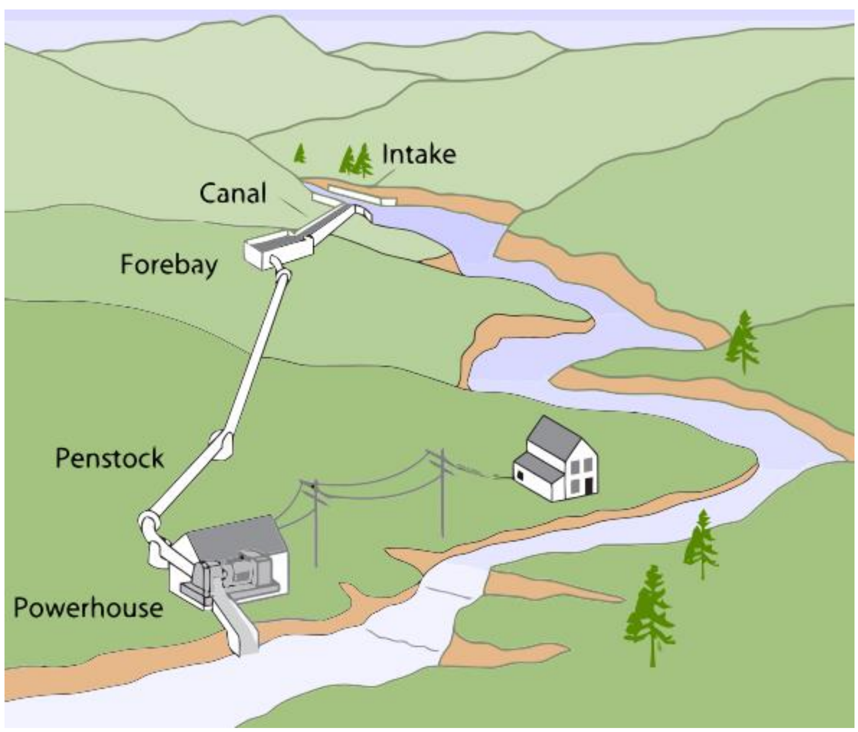
**Option Description**

Micro-hydroelectric power refers to small hydroelectric installations, typically between 5 kW and 100kW, using the natural flow of water in rivers or streams. Micro-hydropower plants (MHPs) are suitable for providing energy for a small community or industrial facility located near a sufficient quantity of falling water. The amount of power that can be obtained from a site is a function of (1) head, the vertical distance of water fall, and (2) flow, the quantity of falling. Because of the requirement of sufficient "head", micro-hydro systems are well suited for remote, mountainous areas.

In Nepal, 30% of the population has no access to electricity. This project will support the development of micro-hydropower mini-grids to meet the electricity needs of the rural people of Nepal through subsidy assistance (representing 40 to 70 percent of the initial investment) and program technical support. These micro-grids will supply power for domestic and institutional lighting and larger micro-hydro systems which can power agro-processing mills, saw mills, and other electric machinery for small cottage industries. The micro-hydro plants will be installed by pre-qualified private sector companies, who will receive subsidy payments, technical assistance and credit support. The plants will be managed by the communities themselves or by the private sector providers. Meters will be installed on each unit, and operating costs will be recovered through tariffs on residential users and larger rural enterprises. The project will lead to reduced GHG emissions by replacing kerosene used for lighting and diesel fuel used for agro-processing and other productive use applications.

This project aligns with the Government of Nepal's 10th National Plan, which aims to increase the electrification rate to 55% through both grid extension and distributed options including micro-hydro and solar, as well as the Hydropower Development Policy, which intends to make institutions operating in the power sector efficient and credit-worthy and increase the participation of the private sector through the introduction of more transparent and investment friendly procedures. The development of small hydro projects and district level projects under decentralized schemes in hilly and remote areas were also highlighted as areas to be developed with support of a subsidy scheme implemented by Nepal's Alternative Energy Promotion Center (AEPC). It will also bring together the rural electrification activities supported through the micro-hydro component of the World Bank Power Development Project and the donor-financed Energy Sector Assistance Program (ESAP II) to expand the total target level of new micro-hydro installations by 15 MW by utilizing the Clean Development Mechanism (CDM) revenues to help meet un-financed program implementation and subsidy costs. The project is consistent with the Country Assistance Strategy (CAS) for Nepal and supports the Poverty Reduction Strategy Paper (PRSP), particularly through providing support for the development of the rural economy and by increasing access to modern energy sources.

**Figure 1. Typical Micro-Hydro Power System**



## Option Design and Implementation

### Goals

The proposed development objectives of the Project are:

- Develop Nepal's hydropower potential in an environmentally and socially sustainable manner so as to meet electricity demand by executing 450 micro-hydro mini-grid projects, generating a total of 15 MW;
- Improve access of rural areas to electricity services by electrifying 142,000 additional households;
- Reduce emissions of greenhouse gases by displacing kerosene and diesel.

### Location

The project area essentially covers Nepal, and any rural household in Nepal is a potential beneficiary. The project will not result in resettlement of people, it is anticipated that there will be no segment of the population that will be adversely affected

### Timing

It is anticipated that 15,000 kW from 450 micro-hydropower plants will be installed between 2003 and 2010, providing access to electricity to an estimated 142,000 households. Each project will take an estimated 2.5 years from identification to completion of construction and training.

### Other

[Use this to indicate any pertinent option design features or issues not covered above. These could be exemptions or thresholds which include or exclude involved entities.]

Use of community labor not only reduces required installation costs, it is necessary to establish local commitment towards the installations.

Sufficient water flow must be established during the feasibility study. Flow data should be gathered over a period of at least one year where possible, so as to ascertain the fluctuation in river flow over the various seasons. Also, measures must be taken during the dry season to assure that there is always enough water to power the turbine, as low water flow can result in a power cut. If such is not clear to consumers from the beginning, then it can seriously endanger the projects' success.

### Implementation Model

[Summary description of the overall process by which the option is moved from startup to final implementation, including a diagram that shows each of the phases and the parties involved and requirements needed for each stage of decisions, including metrics in a table with supporting narrative on stepwise procedures]

**Nepal Micro-Hydro Implementation Model**

| Phase | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| **Phase Name** | Develop Financial and Technical Support Mechanisms | Site Identification and Feasibility Study | Formation of Local Management Groups | Distribution of Funds to Project Developer |
| **Parties Involved** | **World Bank, Alternative Energy Promotion Center (AEPC), UNDP Rural Energy Development Program (REDP)** | **District Development Committees (DDC), Village Development Committees (VDC)** | **AEPC, DDC, Micro Hydro Functional Group (MHFG)** | **Micro Hydro Functional Group (MHFG), DDC/VDC, AEPC** |
| **Legal, Policy, Administrative, and Financial Mechanisms** | World Bank approves Power Development and Carbon Offset Projects.<br>REDP provides project support and technical assistance | Identify potential sites, conduct feasibility and energy demand studies | Organize local meetings to form community Micro Hydro Functional Group (MHFG)<br>AEPC provides technical support training to MHFG for design and construction planning | AEPC extends grants and other project support funds to District Energy Fund managed by District Development Committees for financing approved projects |
| **Analytical Requirements** | Electricity Demand and Emission Reduction Assessment<br>The project stays within the small-scale CDM project eligibility with total electricity generation under 15 MW. | Site feasibility study | | Funds are released only after the acquisition of land for the powerhouse, securitization of the right of way for the canal and distribution lines, and the collection of collateral for any required local loans. |
| **Other Requirements** | National resource assessment for micro-hydro power generation | | | |

**Nepal Micro-Hydro Implementation Model (continued)**

| Phase | 5 | 6 | 7 | 8 |
|---|---|---|---|---|
| **Phase Name** | Manufacturing and Procurement | Construction and Operator Training | Monitoring and Reporting | Project Scale-up |
| **Parties Involved** | **Micro Hydro Functional Group (MHFG), AEPC, local manufacturers** | **Micro Hydro Functional Group (MHFG), AEPC** | **Micro Hydro Functional Group (MHFG), AEPC, DDC, REDP** | **AEPC, DDC** |
| **Legal, Policy, Administrative, and Financial Mechanisms** | Purchasing of micro-hydro generating equipment, from local manufacturers where possible. | MHFG manages construction, hires operators and maintenance staff<br>AEPC provides operator training | Number of systems and meters installed, as well as amount of electricity generated monitored and reported to AEPC and REDP. | Scale-up of projects to the national level based on results from early installations and the national resource assessment. |
| **Analytical Requirements** | | Installation of meters to measure electricity generation.<br>*Although not done in Nepal, consumer metering is also needed to measure consumption and allow for usage-based tariffs.* | | Prioritized list of projects based on local micro-hydro resource, need for power, and lack of other issues (e.g. environmental). |
| **Other Requirements** | | The local beneficiaries are required to provide voluntary labor for construction of civil works and locally available materials required for the installation. | | |

**Planning and Implementation Phases**

[Expand the discussion of each Phase outlined in the Implementation Model above. In Phase 1, identify the initial formative planning requirements needed to support initiation of implementation in subsequent phases of the model. In the final phase, describe what is needed to monitor success of the program/project and to scale-up implementation of similar programs/projects to the jurisdictional scale. For each Implementation Phase, identify the: Parties Involved (those affected by outcomes of the option and those involved in its implementation and their roles); as well as their involvement in the specific Implementation Mechanisms which make up each Implementation Phase (including steps within each phase, as needed). Implementation mechanisms are the legal, administrative, and financial mechanisms needed for implementation]

***Phase 1. Develop Financial and Technical Support Mechanisms.*** To assist GoN in meeting its sector objectives, the World Bank approved a Power Development Project consisting of a $75.6 million IDA credit in 2003.

The project will be implemented by the Alternative Energy Promotion Center (AEPC) with technical assistance provided by UNDP REDP program. AEPC will assume overall management of this project. The REDP project support units will provide project implementation support and technical assistance to the participating communities and the private sector providers.

Funding will be provided by the World Bank, DANIDA/NORAD through the ESAP Phase II program, Government of Nepal, equity contributions and in-kind contributions from the communities, and carbon finance revenues.

This Carbon Offset project will facilitate greenhouse gas emission reductions and support the development of the international market mechanism for trading Emission Reductions (ERs), developed under the framework of the Kyoto Protocol. The Nepal Village Micro Hydro project consists of sale of ERs to the Community Development Carbon Fund (CDCF) which provides carbon finance to small-scale CDM projects in the least developed countries and poorer areas of all developing countries. The CDCF actively seeks to reach countries and communities that are neither presently benefiting from development through carbon finance nor are likely to benefit greatly from it in the future. The CDCF also seeks to support projects which include, as a measurable output, the provision of goods and services that will lead to improvement in the social welfare of the communities involved in the projects.

Phase 1 of this type of project should also include the development of a National Resource Assessment for micro-hydro power to identify areas were projects are technically and economically feasible. This would likely be carried out by AEPC, Nepal Electricity Authority (NEA), and Department of Hydrology and Meteorology (DHM), with assistance from the World Bank.

***Phase 2. Site Identification and Feasibility Study.*** A feasibility study will be conducted at the chosen site to determine if there is sufficient water flow. Flow data should be gathered over a period of at least one year where possible, so as to ascertain the fluctuation in river flow over the various seasons. Also, measures must be taken during dry season to assure that there is always enough water to power the turbine, as low water flow can result in a power cut. If such is not clear to consumers from the beginning, it can seriously endanger the projects' success. The study should also assess whether mid- to long-term climate modeling data indicate any concerns regarding future water supplies (e.g. as presented in the national resource assessment under Phase 1).

***Phase 3. Formation of Local Management Groups.*** Actual implementation of the micro-hydro installations will be managed by local governments, i.e., District Development Committees (DDC) and the Village Development Committees (VDC), and will involve formation of a micro-hydro functional group (MHFG) at each participating community to guide implementation and operation.

Land acquired for the construction of the micro-hydro schemes, including for canal/pipeline, penstock, powerhouse, and distribution line poles, is to be donated voluntarily by each participating community. Micro-hydro schemes will be developed only in those communities where land is voluntarily donated. All land required under the component will be on a voluntary basis. As in the practice under the Power Development Project, Memorandum of Agreements have been established by community functional groups as a means of recording the location and size of land being donated as well as the written consent and names of local witnesses for those community members voluntarily donating land. In addition to the Memorandum of Agreements, which will continue to record and verify the voluntary nature of land donations by each community member, specific provisions will be added to current Memorandum of Agreements to record that the land being donated is free of squatters, encroachers or other claims or encumbrances. In addition, if any loss of income or physical displacement is envisaged, MHFGs will verify the voluntary acceptance of community-devised mitigation measures by those impacted. These will also be recorded in the revised Memorandum of Agreements. MHFGs will identify the land required for the micro-hydro schemes. However, project authorities will confirm whether land identified by MHFGs is suitable for the scheme. The construction of micro-hydro schemes is not expected to result in the involuntary resettlement of any people or structures.

The social mobilization process being followed for the micro hydro village electrification component under the Power Development Project requires the participation of vulnerable and disadvantaged groups in decision-making throughout the design, planning and implementation of micro-hydro schemes. These principles of social mobilization, especially the inclusion of disadvantaged groups in the formation of self-governing community organizations (MHFG's) will continue under the project. Based on the experience thus far with the Power Development Project, formation of MHFG's has typically involved the participation of over 95 percent of the households in the community.

***Phase 4. Distribution of Funds to Project Developer.*** AEPC will extend grants and other project support funds to a District Energy Fund (DEF) managed by District Development Committees for financing approved micro-hydro project proposals. Funds are released from the DEF only after the acquisition of land for the powerhouse, securitization of the right of way for the canal and distribution lines, and the collection of collateral for any required local loans. Investment grants or subsidies are then released based on output verification, while other costs such as for social mobilization, training, etc. are paid on an actual cost basis. Expenditure statements are submitted through the DDCs to AEPC, who confirms eligibility of expenditures.

***Phase 5. Manufacturing and Procurement.*** DDC and/or VDC will coordinate purchase of generators and other equipment. Where possible, these will be obtained from local manufacturers. These is a well-developed manufacturing capability within Nepal for construction of micro-hydro plants.

***Phase 6. Construction and Operator Training.*** The local beneficiaries are required to provide voluntary labor for construction of civil works and locally available materials required for the installation. Meters will be installed on each generating unit to monitor generated electricity.

Installation of metering equipment on end-users to collect information on consumption and allow usage-based tariffs is also recommended. However, in the Nepal MHP project, meters were generally not installed on households, because electricity consumption is so low in these rural areas, the costs associated with meters: installation, meter reading, and account keeping, could be higher than the revenue generated. Tariffs are set as flat rates based on number of lightbulbs or social status, and in some cases, a cut off device is used to limit consumption to 100W.

Extensive training for the operation and maintenance (O&M) staff (two operators and one manager selected from the local community) assigned to each system is being provided through the project, in both technical aspects of system operation and in bill collection, disconnection for non-payment, record keeping, accounting, etc. O&M staff are engaged prior to commencement of construction, are required to sign pledges that prevent them from leaving for other opportunities once training is completed, and are required to assist with system construction, plant installation and commissioning.

***Phase 7. Monitoring and Reporting.*** Monitoring and evaluation will be undertaken through two mechanisms, the World Bank supervision of the ongoing Power Development project and through the specific monitoring plan for Verification of Emissions Reductions that will be developed in the CDM Project Design Document. The monitoring parameters of the CDM program shall include the number of kWh produced by each micro-hydro unit as measured by the individual meters, and the number of households connected to the micro-hydro plant. AEPC will be accountable for overall reporting on implementation progress, preparation of financial monitoring reports, and preparation of audited project accounts. REDP district staff shall conduct regular monitoring of the installed plants. AEPC shall also conduct enhanced verification and quality assurance activities. A monitoring and verification plan for the community benefits of the program will be developed as required by the CDCF. It will be built upon the existing monitoring and evaluation activities undertaken by AEPC under the World Bank Power Development Project and the annual impact assessment reports.

***Phase 8. Project Scale-up.*** The total electricity generation under this project will be kept under 15 MW to remain within the eligibility requirement for small-scale CDM projects.

Although the Government of Nepal (GoN) Environmental Regulations do not require that micro hydro village electrification projects be below 1 MW to seek environmental clearance, all such projects will be required to undertake a simple environmental assessment and prepare an Environmental Management Plan. This plan will be reviewed, cleared, and subsequently monitored by AEPC, on behalf of GoN. In addition, during subproject approval and supervision, AEPC will ensure that carpentry workshops will use timber only from entitled quotas from the respective community user groups.

After implementation of an initial set of local projects, the project will be scaled-up based on results from these early installations. The National Resources Assessment developed as part of Phase 1, provides the information needed to develop a prioritized list of projects based on local micro-hydro resources, need for power, and lack of other issues (e.g. environmental).

**Parties Involved**

[Briefly summarize those affected by outcomes of the option and those involved in its implementation and their roles, including involvement in implementation mechanisms as detailed above.]

***Government of Nepal:*** Establishes electrification and renewable energy goals; conducts national resource assessment.

***World Bank:*** Approves the Power Development Project and Carbon Offset Project.

**Alternative Energy Promotion Center (AEPC):** Implements and manages project; leads scale-up of additional projects to the national-level.

**UNDP Rural Energy Development Program (REDP):** Provides project implementation support and technical assistance to the participating communities and the private sector providers.

**District Development Committees (DDC) / Village Development Committees (VDC):** Manages local projects, forms local micro-hydro functional groups (MHFG), manages District Energy Fund (DEF) that receives funds through AEPC.

**Micro Hydro Functional Group (MHFG):** acquires land for the power house, secures right of way for the canal and distribution lines, and the collects of collateral for any required local loans with support of DDC/VDC.

**Baseline Conditions**

[This should also capture the relevant elements of any existing and/or planned actions at the subnational/national level that affect implementation of the option. Measures are designed to be incremental to existing and planned actions (baselines). Add information that is more detailed regards location and timing. Include a description of any existing program and the relationship to the option (for example, applicable emissions offsets, funding source).]

The project seeks to develop a viable off-grid micro-hydropower market for villages, which will not be served by the national grid for at least 5 years. These villages are currently using kerosene for domestic lighting and diesel generators for other power needs.

**Metrics for Implementation Assessment**

[Create a general equation followed by the procedure by which it will be customized to the technology/policy measure at broad as well as specific level through use of methods and metrics.]

**Energy and RE Technology Demand**

1. Key Issues

   *Based on the national baseline report, Nepal's electricity demand in 2015 was XX GWh. Broken down by end use, the residential sector demanded XX%, the commercial/institutional sector XX%, and the industrial sector XX%. Under BAU conditions, electricity demand is expected to grow to XX GWh by 2035. By that year, the residential sector is expected to demand XX% of the total, the commercial/institutional sector XX%, and the industrial sector XX%.*

   *Demand for kerosene and diesel fuels in 2015 was XX TJ ad XX TJ, respectively. For kerosene, the residential sector demanded XX%, the commercial/institutional sector XX%, and the industrial sector XX%. For diesel, the residential sector demanded XX%, the commercial/institutional sector XX%, and the industrial sector XX%. Under BAU conditions, kerosene demand is expected to grow to XX TJ by 2035 and diesel is expected to grow to XX TJ. For kerosene in 2035, the residential sector is expected to demand XX% of the total, the commercial/institutional sector XX%, and the industrial sector XX%. For diesel, the residential sector is expected to demand XX% of the total, the commercial/institutional sector XX%, and the industrial sector XX%.*

Relative lack of productive uses means that electricity consumption is heavily concentrated in the peak evening hours, resulting in a low load factor (the load factor is the ratio of average consumption to the total possible consumption). From a financial point of view, it is preferable that demand be evenly spread throughout the day (because installed capacity has to meet maximum demand, but is idle for much of the time with a low load factor). The financial viability of RE is therefore linked to promoting productive uses. Alternatively, energy storage systems could be included as part of the project to allow for capturing excess generation during periods of low demand.

2. Methodology: Local Energy Demand

[Include general methods and metrics for the option.]

Estimate energy demand for each end use sector (residential, commercial/institutional, and industrial). Since MHPs will likely replace kerosene for lighting and diesel generators in rural areas, both direct fuel use and electricity consumption should be estimated.

a. Begin with location-specific historical consumption for each end use sector:

   i. $R_f$, $CI_f$, $I_f$ - Residential, commercial/institutional, and industrial fuel demand for kerosene and diesel for the historical base year (TJ). Note: further disaggregation to subsectors is also highly valuable if available (e.g. rural vs. urban residential; commercial vs. institutional; disaggregation for key electricity consumption subsectors)

   ii. $R_e$, $CI_e$, $I_e$ - Residential, commercial/institutional, and industrial electricity demand for the historical base year (MWh). Note: further disaggregation to subsectors is also highly valuable if available (e.g. rural vs. urban residential; commercial vs. institutional; disaggregation for key electricity consumption subsectors)

   iii. For forecasting methods development, consider the provincial-level forecasting methods from the LCD Toolkit as a starting point for further refinement. These are in 2 separate memos located on iMC: one for the residential, commercial and institutional sectors; the other for the industrial sector. Higher levels of sophistication could be added to these forecasting methods to address expected changes in climate (leading to greater demands for heating or cooling); and energy price effects (e.g. elasticity of demand to future prices in electricity).

b. Include equations for estimating local electricity demand by sector. As a generic example:

   i. Electricity Load Growth = ƒ (population, income growth, climate changes, technology innovation, price elasticity)

   ii. Allocation of sector-based load to energy end use: % heating/cooling, lighting, cooking, water heating, remaining plug load.

   iii. Diurnal profile summaries of sector-based load by season for key target years.

   iv.

3. Key Metrics: Local Energy Demand

a. Electricity and direct fuels price forecasts

b. Elasticity of energy demand by end use sector

c. End use technology mix and shifts (possibly, as a function of income): lights, fans, A/C, refrigeration, appliances, equipment

d. Population, economic and income status and growth (rural versus urban breakdowns)

e. Climate change effects on heating and cooling demand

f. Breakdown of sector demand by end use (lighting, heating, cooling, appliances, other) and technology innovation rate impacts on consumption by end use

g. Policy incentives

    i. Caps: stringency, baseline GHG intensity, flexibility, value of allowances

    ii. Other policies and requirements if/as needed

**Energy Supply**

1. Key Issues

[Describe the key issues that need to be addressed. Summarize the jurisdictional energy supply baseline, including what new generation sources are expected to be put in place in the future under business as usual (BAU) conditions to meet future load growth. Also, how will the RE option being considered impact the BAU generation system (e.g. if it is tied to the grid or not, if it ties to a grid that serves the entire jurisdiction or to a smaller independent grid)?

The remaining sections address the RE technology for this option.]

Nepal Electricity Authority (NEA) owns Hydroelectric Plants connected to the grid amounting to 480 MW. It also buys power from Independent Power Producers (IPP) amounting to 230 MW. It operates two diesel operated plants generating 53 Megawatts of Electricity. Total sales of electricity in 2016 were 3,746 GWh. The average consumer's annual consumption was 1,261 kWh.

The MHPs installed as part of this project are not associated with national grid, but are expected to replace kerosene for lighting and small diesel generators for electricity.

2. Methodology: Local RE Supply

    a. Local Resource Assessment:

        i. The potential electricity generation capacity at a particular MHP site is estimated with the following equation:

$$P = h \times f \times d \times g \times e$$

where:
$P$ = potential power (watts);
$h$ = head; the vertical distance that the water falls (m);
$f$ = water flow rate ($m^3/s$);
$d$ = density of water (1,000 $kg/m^3$);
$g$ = gravity (9.81 $m/s^2$);
$e$ = water to wire efficiency (typically around 75%).

*ii.* Renewable power production. The general equation for net renewable power generation is:

$$RP = PC \times C_f \times OU_f \times 8760$$

where:
RP = Net renewable power generation (MWh/yr)
PC = Plant capacity (gross MW)
$C_f$ = Plant capacity factor (unitless; account for down-time by the plant for maintenance, low water flow, etc.)
$OU_f$ = Plant own-use factor (unitless; fraction of gross output used on-site for plant needs; sometimes referred to as "parasitic losses")
8760 = hours per year

b. Supply Technology Considerations:

i. Sufficient water flow must be established during the feasibility study. Flow data should be gathered over a period of at least one year where possible, so as to ascertain the fluctuation in river flow over the various seasons. Also, measures must be taken during dry season to assure that there is always enough water to power the turbine, as low water flow can result in a power cut. If such is not clear to consumers from the beginning, it can seriously endanger the projects' success. Water flow studies should also evaluate potential long-term water flow conditions related to the impacts of climate change.

ii. MHP capital and operating costs[85]:

1. Generation characteristics: Variable sized systems

2. Installation costs: The cost of an MHP is highly variable and site specific, depending on the remoteness of the site, physical features, and major equipment components of the projects. The cost of civil works depends on the gradient of the waterway, and the cost of electrical lines depends on the energy density of load centers.

**Component Construction Costs of Representative MHPs**

| Project | Size | Cost, $/kW | | | |
|---|---|---|---|---|---|
| | | Civil Works | Generation Equipment | Electric Lines | MHP Total |
| Gaura Rice Mill, Baglung | 19 kW | 379 | 578 | 322 | **1,279** |
| Barpak MHP | 46.5 kW | 308 | 247 | 493 | **1,530** |
| Pemba Gelu, Solukhumbu | 12 kW | 630 | 574 | 540 | **2,057** |
| Radhalaxmi, Ilam | 7.5 kW | | 574 | 788 | **1,759** |

[85] *Cost and Revenue Structures for Micro-Hydro Projects in Nepal*: http://www.microhydropower.net/download/mhpcosts.pdf.

| | | | | | |
|---|---|---|---|---|---|
| Ghandruk MHP | 50 kW | | | | **2,180** |
| Bhujung MHP | 80 kW | 1,170 | 380 | 517 | **2,067** |
| Sikles MHP | 120 kW | | | | **2,350** |

3. Operation & maintenance (O&M) costs:

   O&M costs include repair and maintenance, labor, depreciation and interest charge on loan. Plants are usually designed to meet certain load growth in the future; because once built, capacity may not be easily extendable. Therefore, in the initial years, revenue as a percentage of total costs would tend to be lower.

   When estimating O&M, long term cost situations should be considered. Expenses like major repair/maintenance of machinery and replacement of poles would not happen every year. The representative operating costs shown below are based on data from 4 to 14 years of operation for the MHPs and yearly budget data for small hydro plants (SHPs).

**Operating Costs of Representative MHPs and Small Hydro Plants (SHPs)**

| | | **O&M Cost** | | **Total Cost (O&M plus annualized installation)** | |
|---|---|---|---|---|---|
| **Project** | **Size** | **% of Investment** | **% of Revenue** | **% of Investment** | **% of Revenue** |
| Gaura Rice Mill, Baglung | 19 kW | 10 | 60 | 17 | 106 |
| Barpak MHP | 46.5 kW | 7 | 33 | 21 | 99 |
| Pemba Gelu, Solukhumbu | 12 kW | 8 | 62 | 21 | 173 |
| Radhalaxmi, Ilam | 7.5 kW | 14 | 45 | 25 | 81 |
| Jomsom SHP | 240 kW | 6 | 42.5 | 7 | 50 |
| Khandbari SHP | 250 kW | 5 | 44 | 8 | 73 |
| Bajhang SHP | 200 kW | 2 | 69 | 4 | 80 |
| Darchula SHP | 300 kW | N/A | 50 | N/A | 85 |

4. Load Factor:

Load factor refers to the ratio of the average load divided by peak load, and is a measure of the variability of generation. Lack of sufficient training for MHP plant operating staff results in longer downtime for repairs and maintenance, lowering the load factor and reducing potential revenue. Load factors of representative plants shown below take into account system technical losses.

**Load Factors of Representative MHPs and Small Hydro Plants (SHPs)**

| Project | Size | Load Factor (%) |
|---|---|---|
| Gaura Rice Mill, Baglung | 19 kW | 29 |
| Barpak MHP | 46.5 kW | 31 |
| Pemba Gelu, Solukhumbu | 12 kW | 21 |
| Radhalaxmi, Ilam | 7.5 kW | 32 |
| Jomsom SHP | 240 kW | 44 |
| Khandbari SHP | 250 kW | 35 |
| Bajhang SHP | 200 kW | 18 |
| Darchula SHP | 300 kW | 17 |

5. Tariff Structure:

   There is no standard guideline for determining tariff structure for MHPs. The tariff must balance revenue needs with the ability of customers to pay for service. Also, attempts should be made to avoid peaking and a poor load factor by maintaining the capacity demand tariff sufficiently high.

   The flat rate tariff for most representative MHPs range from RS 0.25 per watt per month to RS 2 per watt per month. Based on typical usage hours of 4 to 5 hours per day for bulbs, a RS 0.50 to RS 1 per watt per month would compare with the Nepal Electric Authority (NEA) tariff for low level domestic consumers.[86] However, considering typical operating costs of a MHP, a flat tariff of less than RS 1 per watt per month may not result in an operating surplus, unless there are sufficient day-time end uses contributing to the revenue. Gaura Rice mill, Baglung, is a case

[86] A flat rate tariff structure was used for the Nepal MHP project; however this may not be the optimal choice for tariff structure since it does not measure consumption. Unless installation of end-use meters a cost prohibitive, consumption-based metering and tariff rates are recommended.

example where the annual revenue almost covers all of the operating expenses despite a relatively low electricity tariff rate.

**Metered Tariff Structures of Representative MHPs and SHPs**

| Project | Size | Tariff, RS/kWh | | |
|---|---|---|---|---|
| | | Domestic | Non-domestic | Average |
| Gaura Rice Mill, Baglung | 19 kW | 2.43 | 2.54 | 2.5 |
| Barpak MHP | 46.5 kW | 6.59 | 4.55 | 5.72 |
| Pemba Gelu, Solukhumbu | 12 kW | 4.61 | 7.21 | 6.6 |
| Radhalaxmi, Ilam | 7.5 kW | 4.21 | 2.82 | 3.14 |
| Jomsom SHP | 240 kW | 3.96 | 5.49 | 4.54 |
| Khandbari SHP | 250 kW | 4.43 | 5.84 | 3.74 |
| Bajhang SHP | 200 kW | 4.05 | 6.9 | 4.59 |
| Darchula SHP | 300 kW | 3.73 | 5.27 | 4.2 |
| Ghandruk MHP | 50 kW | 6 | 2.5 | 4.4 |

6. Financing:

Funding will be provided by the World Bank, Danish International Development Agengy (DANIDA)/Norweigan Agency for Development Cooperation (NORAD) through the ESAP Phase II program, GoN, equity contributions and in-kind contributions from the communities, and carbon finance revenues.

The World Bank funding through IDA for the project was US$75.6 million during 2004-2009 with a grant of US$5.5 million for the micro-hydro project component only. The remaining cost was covered through cash and labor counterpart provided by participating communities and the Government of Nepal. Under the REDP framework, the programme provides support up to 50% of the total non-local cost required for installation of micro-hydro. The communities were also assisted to mobilize financial resources in the form of grants, loans and investment from local authorities, such as District Development Committee (DDC) and Village Development Committee (VDC), government line agencies and development banks. The DDC and VDC usually contribute about 10% of the total non-local cost in each demonstration scheme. The local beneficiaries also provide voluntary labor and locally available materials required for the installation.

**Nepal MHP Project Financing**

| Source | US $Million |
|---|---|
| Government of Nepal | 2.26 |
| Domestic borrowing / Equity investment | 26.9 |
| International Bank for Reconstruction and Development IDA Grant | 9.4 |
| UNDP | 3.57 |
| DANIDA/NORAD | 14.3 |
| Carbon Finance | 1.9 |
| Financing gap | 0.65 |
| **Total** | **59.08** |

3. <u>Key Metrics</u>
    a. MHP and Micro-grid Technology Project Costs: $59 million
    b. Operations & Maintenance Costs: These costs were not available from the project documentation; therefore, assumed values of $5/MWh for variable O&M and $26/kW-yr for fixed O&M were taken from a World Bank report.[87]
    *c.* Levelized cost of electricity (LCOE) – Compare to LCOE values for other BAU generation sources. Optimally, these come from the electricity provider; but values from the literature could be used as back-up.

*Initial Investment Costs (IIC)*[88]*:* These costs are annualized to $/MWh units for each year of expected plant operation as per the formula below:

$$Annualized\ IIC = IIC * FCF * 1000 / (8760 * C_f)$$

where:
IIC = initial investment costs. These include the capital costs of land and equipment, as well as any other initial costs for planning, engineering and construction ($/kW)
$C_f$ = capacity factor (%)

[87] The World Bank Group, Energy Unit, Energy, Transport and Water Department, 2006. Technical and Economic Assessment of Grid, Mini-Grid and Off-Grade Electrification Technologies Annexes. http://siteresources.worldbank.org/EXTENERGY/Resources/336805-1157034157861/ElectrificationAssessmentRptAnnexesFINAL17May07.pdf.
[88] Typically reported in units of $/kW, these costs include the total costs of construction, including land purchase, land development, permitting, interconnections, equipment, materials and all other components. Construction financing costs are also included.

8760 = hours per year
FCF = fixed charge factor[89]
1000 = conversion from $/kW to $/MW

*Fixed O&M (FOM)[90]:* These costs are estimated for each year of plant operation in $/MWh units as per the formula below:

$$\textit{Annualized fixed O\&M cost} = FOM * 1000 / (8760 * C_f)$$

where:
FOM = fixed O&M ($/kW-yr)
$C_f$ = capacity factor (%)
8760 = hours per year
1000 = conversion from $/kW to $/MW

*Variable O&M (VOM)[91]:* These costs should already be provided in units of $/MWh, so no conversion is needed.
*Fuel costs (FC):* Each year's fuel price is converted to units of $/MWh as follows:

$$\textit{Annual Fuel Cost} = FP_t * HR$$

where:
$FP_t$ = fuel price in year t ($/TJ)
HR = gross heat rate (TJ/MWh)
t = year in the plant lifetime

*Discounted Costs:* All of the annual costs estimated above are then discounted as follows:

$$\textit{Discounted Annual Costs} = [PV_{GEN} * DR * (1+DR)^t] / [(1 + DR)^t - 1]$$

where:
$PV_{GEN}$ = present value of the sum of all generation costs = annualized IIC + FOM + VOM + FC ($/MWh in each year of the plant's lifetime)
DR = discount rate

The values in the stream of discounted annualized costs are then levelized across the lifetime of the plant:

$$LCOE = \sum \text{Discounted Annual Costs}/PL$$

where:
LCOE = levelized cost of electricity ($/MWh)
PL = lifetime of the plant (years)

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[89] This factor is calculated based on assumptions regarding the plant lifetime, the effective interest rate or discount rate used to amortize capital costs, and various other factors specific to the power industry. Expressed as a decimal, typical fixed charge factors are typically between 0.10 and 0.20, meaning that the annual cost of ownership of a power generation technology is typically between 10 and 20 percent of the capital cost. Fixed charge factors decrease with longer plant lifetimes, and increase with higher discount or interest rates.
[90] Typically reported in units of $/kW-yr, these costs are for those that occur on an annual basis regardless of how much the plant operates. They typically include staffing, overhead, regulatory filings, and miscellaneous direct costs.
[91] Typically reported in units of $/MWh, these costs are for those that occur on an annual basis based on how much the plant operates. They typically include costs associated with maintenance and overhauls, including repairs for forced outages, consumables such as chemicals for pollution control equipment or boiler maintenance, water use, and other environmental compliance costs.

4. Project Impact:
    a. GHG reduction from BAU (tonnes of $CO_2$ equivalent or $tCO_2e$): The project is estimated to result in GHG reductions of 36,800 $tCO_2e$/yr. This value is based on an estimated demand of 27 kWh/HH/month and UNDP default value of 0.8 tCO2e/MWh for diesel generation units.
    b. Renewable electricity production: The project is estimated to generate 36,800 MWh of renewable energy per year.
    c. Contribution toward jurisdictional target(s):
    d. Job creation:

## Results of Assessment

[This section is where the quantification results are presented and discussed.]

**RE Energy and Emissions Assessment Results**

| **Program/Project – Level Results** | | | | |
|---|---|---|---|---|
| **2035 RE Generation (GWh)** | **2020 - 2035 RE Generation (GWh)** | **2035 Power Demand Met (%)** | **2035 GHG Reduction ($tCO_2e$)** | **2020 – 2035 GHG Reduction ($TgCO_2e$)** |
| 36.8 | 567 | | 36,800 | 515 |
| **Potential Jurisdictional – Level Impacts** | | | | |
| **2035 RE Generation (GWh)** | **2020 - 2035 RE Generation (GWh)** | **2035 Power Demand Met (%)** | **2035 GHG Reduction ($tCO_2e$)** | **2020 – 2035 GHG Reduction ($TgCO_2e$)** |
| | | | | |

**RE Technology Market Assessment**

| **Capacity of Resource (GW)** | **Annual Net Generation (GWh)** | **Metric C** | **Metric D** | **Metric E** |
|---|---|---|---|---|
| *Provincial (Local) Level* | | | | |
| | | | | |
| *National Scale-Up* | | | | |

| | | | | |
|---|---|---|---|---|
| 300 | 1,800 | | | |

**Program/Project Financial Assessment**

| Program/Project – Level Results | | | | |
|---|---|---|---|---|
| Initial Investment Costs ($MM 2017) | NPV of Implementation Costs ($MM 2017) | Discounted Payback (Years) | Internal Rate of Return (%) | Risk-Adjusted Return on Investment (%) |
| 59 | 20 | 6.5 | 17 | 185 |

### A. Jurisdictional and Local Energy Supply and Demand

[This section will be completed based on the results of the demand/supply assessments, financing, and trading and other ancillary policy impacts. List the relevant metrics and results, perhaps in table to simplify, and then provide a step-wise description of the process used for evaluating metrics.]

- **Direct, Indirect, and Integrative Impacts**
    - [This section is where the summary of results for energy supply and demand provided above is documented. This also is where a link or reference to more detailed analysis and results can be found. Direct results include power generation/other energy and emissions impacts. Indirect results should either be quantified or at least qualitatively cited. These include energy and emissions impacts on upstream fuel supplies. Integrative impacts include jurisdictional level generation and emissions impacts resulting from scaling the technology up to that scale]
- **Key Uncertainties**
    - [This section addresses key uncertainties and any methods for addressing them in quantification results above.]
- **Feasibility Issues**
    - [This section addresses key feasibility issues identified and addressed or not addressed in the assessment and their implications.]

### B. RE Technology Demand

[Summarize the results of the RE technology market assessment summarized in the table at the beginning of this section.] The following factors are important to understanding RE market potential for MHD in Nepal: rural electricity demand by province/district; available head and water volume for MHD generation by province/district; levelized cost of electricity (LCOE) for MHD versus other alternatives (including fossil fuels); and financial risk analysis (see Subsection C below).

- Technical viability: e.g. equipment feasibility/maturity; head and water volume availability; baseload demand growth for the local electrical grid.
- Local RE Market Potential
    a. Approach for assessing local RE market potential

  Comparison of the LCOE for the technology to other alternatives with and without incentives; etc.

    b. Key Metrics

  Jurisdictional RE Market Potential (Scale-Up)

    g. Approach for assessing Jurisdictional Market Potential
    h. Key Metrics

**C. Financial Assessment**

[Use the same template as for Energy Demand, above.]

- Financial risk, return, and impact. Two relevant categories of financial risk are *market* risk and *credit* risk. *Market* risk refers to the risk of a changing conditions in the marketplace that could impact the viability of the RE technology being deployed (for example, advances in technology that make the financed project obsolete). *Credit* risk is the risk that lenders incur by extending credit to borrowers. Lenders take on a risk that borrowers could default on payments.]
- Data sources methods, key assumptions, uncertainty, feasibility issues for each of the financial assessment metrics are described below. General assumptions applied here as well as in the rest of the impacts analysis include an inflation rate of 4% and a discount rate of 10%:

  ***Discounted net cash flow (DCF) and net present value (NPV) of implementation costs.*** The NPV of implementation costs was developed by assembling all costs and income components across the total lifetime of 15MW of micro-hydro plants. The micro-hydro systems were assumed to be installed over a 15 year period and to have 30 year life span. Electricity tariffs were assumed to equal $0.20/kWh.

  Total project costs, including installation, training, and other project costs, were $59 million US, taken from available project documentation.[92] The capacity factor for the micro-hydro plants was assumed to be 0.30. Other variable operations and maintenance (O&M) and fixed O&M costs were not provided in project documentation. Values for these were taken from a World Bank study. Annual escalation of O&M cost was also taken from the same study (2.25%/yr).

  The financial structure of the project includes domestic and international grants and loans. Community provided equity was assumed to be 10%. The finance rate for loans was assumed to be 16% over 20 years.

[92] Nepal Village Micro Hydro Project Documentation: http://projects.worldbank.org/P095978/nepal-village-micro-hydro?lang=en&tab=documents&subTab=projectDocuments.

Revenue for the plant is from electricity sales. The tariff on electricity was assumed to be \$0.20/kWh. The project budget also included Carbon Offsets of \$1.9 million.

With the above inputs, a discounted net cash flow (DNCF) for the project was developed along with a discounted NPV of total implementation costs. The period of analysis covers the entire project lifetime (through 2041). The NCF analysis is done from the perspective of the project developer. This means that rather than using the total project installation costs, these costs are annualized, and that annualized stream of costs for debt service is used as one of the cash flows along with the initial equity payment and O&M costs. The sum of DNCF is calculated as:

$$\sum DNCF = E + \sum DS + \sum FOM + \sum F + \sum VOM + \sum T + \sum R_{PS} + \sum Sub + \sum R_O$$

Where all values have been discounted to 2017 US dollars:

E = initial equity payment by project developer
DS = annual debt service payment
FOM = annual fixed O&M costs
F = annual fuel costs
VOM = annual other variable O&M costs
T = annual tax payments
$R_{PS}$ = annual revenue for power sales
Sub = annual government subsidy (feed-in tariff)
$R_O$ = annual revenue from other sources (e.g. fly ash sales)
Note – all cost values are negative; all revenue values are positive.

The DCF for the Nepal Micro-Hydro Project is shown in the table below. The sum of DCF for the project developer is shown to be \$45 million (\$2017).

The NCF analysis involves subtracting the total costs from the project revenues in each year. These annual net costs are then discounted back to \$2007 using the 10% discount rate. Separate NCF estimates were calculated from the perspective of the project developer, as well as for the project overall. The difference is that the NCF for the project developer takes into account the financing assumptions on total installation costs, while the NCF for the project overall excludes these (i.e. costs in year 1 include total installation costs). The discounted NCF value reported in the summary table above is for the project developer. The financial flows are summarized in the table below.

***Risk-Adjusted Return on Investment (ROI).***

***Internal Rate of Return (IRR).*** IRR is closely related to NPV, the net present value function. The rate of return calculated by IRR is the interest rate corresponding to a 0 (zero) net present value. The IRR for the Nepal Micro-Hydro Project is estimated to be 17.7%.

## Financial Flows Summary: Nepal Micro-Hydro Project

| Year | Total Installation Costs ($) | Total Installed Net Capacity (MW) | Equity ($) | Debt Service ($) | Fuel Costs ($) | Other Variable O&M ($) | Fixed O&M ($) | Taxes ($) | Renewable Energy Credits Revenue ($) | Net Generation (MWh) | Power Revenue ($) | Feed-In Tariff ($) | Other Revenue ($) | Developer's Net Cash Flow ($) | Developer's Discounted NCF ($2017) | Project Discounted NCF ($2017) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2018 | ($11,799,000) | 2.8 | ($1,179,900) | ($533,896) | $0 | ($36,792) | ($14,560) | ($220,752) | $379,693 | 7,358 | $1,471,680 | $0 | $0 | $86,225 | $78,387 | ($9,089,980.51) |
| 2019 | ($11,799,000) | 5.6 | ($1,179,900) | ($1,067,792) | $0 | ($73,584) | ($29,775) | ($441,504) | $759,387 | 14,717 | $2,943,360 | $0 | $0 | $1,351,695 | $1,117,104 | ($6,776,539.11) |
| 2020 | ($11,799,000) | 8.4 | ($1,179,900) | ($1,601,689) | $0 | ($110,376) | ($45,668) | ($662,256) | $1,139,080 | 22,075 | $4,415,040 | $0 | $0 | $2,616,488 | $1,965,806 | ($4,809,108.48) |
| 2021 | ($11,799,000) | 11.2 | ($1,179,900) | ($2,135,585) | $0 | ($150,479) | ($62,260) | ($883,008) | $1,518,774 | 29,434 | $5,886,720 | $0 | $0 | $3,877,269 | $2,648,227 | ($3,146,127.88) |
| 2022 | ($11,799,000) | 14.0 | ($1,179,900) | ($2,669,481) | $0 | ($192,331) | ($79,576) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $5,135,578 | $3,188,790 | ($1,747,297.81) |
| 2023 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($196,659) | ($81,367) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,309,360 | $3,561,469 | $5,068,321.94 |
| 2024 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($201,084) | ($83,198) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,303,105 | $3,234,489 | $4,604,355.30 |
| 2025 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($205,608) | ($85,070) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,296,709 | $2,937,461 | $4,182,793.61 |
| 2026 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($210,234) | ($86,984) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,290,168 | $2,667,645 | $3,799,765.94 |
| 2027 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($214,964) | ($88,941) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,283,481 | $2,422,554 | $3,451,754.39 |
| 2028 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($219,801) | ($90,942) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,276,643 | $2,199,925 | $3,135,561.90 |
| 2029 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($224,747) | ($92,988) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,269,651 | $1,997,704 | $2,848,283.04 |
| 2030 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($229,803) | ($95,080) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,262,502 | $1,814,024 | $2,587,277.40 |
| 2031 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($234,974) | ($97,220) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,255,192 | $1,647,188 | $2,350,145.44 |
| 2032 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($240,261) | ($99,407) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,247,718 | $1,495,654 | $2,134,706.56 |
| 2033 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($245,667) | ($101,644) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,240,075 | $1,358,022 | $1,938,979.09 |
| 2034 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($251,194) | ($103,931) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,232,261 | $1,233,020 | $1,761,162.20 |
| 2035 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($256,846) | ($106,269) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,224,271 | $1,119,490 | $1,599,619.42 |
| 2036 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($262,625) | ($108,660) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,216,101 | $1,016,382 | $1,452,863.60 |
| 2037 | $0 | 14.0 | $0 | ($2,669,481) | $0 | ($268,534) | ($111,105) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,207,747 | $922,742 | $1,319,543.33 |
| 2038 | $0 | 14.0 | $0 | ($2,135,585) | $0 | ($274,576) | ($113,605) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,733,101 | $909,848 | $1,198,430.58 |
| 2039 | $0 | 14.0 | $0 | ($1,601,689) | $0 | ($280,754) | ($116,161) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $7,258,263 | $891,648 | $1,088,409.39 |
| 2040 | $0 | 14.0 | $0 | ($1,067,792) | $0 | ($287,071) | ($118,775) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $7,783,229 | $869,217 | $988,465.73 |
| 2041 | $0 | 14.0 | $0 | ($533,896) | $0 | ($293,530) | ($121,447) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $8,307,993 | $843,474 | $897,678.13 |
| 2042 | $0 | 14.0 | $0 | $0 | $0 | ($300,135) | ($124,180) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,934,085 | $639,988 | $815,209.26 |
| 2043 | $0 | 14.0 | $0 | $0 | $0 | ($306,888) | ($126,974) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,924,538 | $581,007 | $740,298.27 |
| 2044 | $0 | 14.0 | $0 | $0 | $0 | ($313,793) | ($129,831) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,914,776 | $527,443 | $672,253.82 |
| 2045 | $0 | 14.0 | $0 | $0 | $0 | ($320,853) | ($132,752) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,904,795 | $478,802 | $610,447.68 |
| 2046 | $0 | 14.0 | $0 | $0 | $0 | ($328,072) | ($135,739) | ($1,103,760) | $1,898,467 | 36,792 | $7,358,400 | $0 | $0 | $6,894,589 | $434,631 | $434,631 |
| 2047 | $0 | 11.2 | $0 | $0 | $0 | ($268,363) | ($111,034) | ($883,008) | $1,518,774 | 29,434 | $5,886,720 | $0 | $0 | $5,507,322 | $315,617 | $315,617 |
| 2048 | $0 | 8.4 | $0 | $0 | $0 | ($205,801) | ($85,150) | ($662,256) | $1,139,080 | 22,075 | $4,415,040 | $0 | $0 | $4,124,089 | $214,860 | $214,860 |
| 2049 | $0 | 5.6 | $0 | $0 | $0 | ($140,288) | ($58,044) | ($441,504) | $759,387 | 14,717 | $2,943,360 | $0 | $0 | $2,745,029 | $130,011 | $130,011 |
| 2050 | $0 | 2.8 | $0 | $0 | $0 | ($71,722) | ($29,675) | ($220,752) | $379,693 | 7,358 | $1,471,680 | $0 | $0 | $1,370,283 | $59,000 | $59,000 |
| 2051 | $0 | - | $0 | $0 | $0 | $0 | $0 | $0 | $0 | - | $0 | $0 | $0 | $0 | $0 | $0 |

**D. Trading and Other Policies**

[Use the same template as for Energy Demand, above.]

- Direct, indirect, and integrative effects including stringency, flexibility, and values
- Data sources methods, key assumptions, uncertainty, feasibility issues

**Additional Impacts**

[If needed, this section can include outcomes or outputs of analysis that are not included in the quantification section and the metrics it covers, and can include a more limited approach to analysis or qualitative discussion of key impacts.]

The environmental impacts of micro hydro projects are generally small, with the main impacts are (1) the partial de-watering of a section of riverbed from the intake until water is returned to the river downstream of the powerhouse, and the consequent effect on aquatic life in the dewatered section; (2) potential ground / soil erosion caused by flushing flows discharged from sedimentation basins and by overflows at the forebay, (3) potential ground instability caused by canal/pipe construction and leakage from canals; (4) cutting of forest cover to make way for construction works, and (5) cutting of trees for use as power poles. Considering the small size of these sub-projects, it is not anticipated that there will be any road construction. In the unlikely event there are unanticipated impacts, the environmental mitigation plans developed for each sub-project will address the problems with suitable mitigation measures.

The impact of project and the installation of micro-hydro system not only provides electric power to the households, but also improves the quality of life of the entire village by providing opportunities for income generation and education. Apart from lighting, it also provides mechanical energy for milling, husking, grinding, carpentry, spinning and pump irrigation in the village, which paid off in the form of higher local incomes.

**Status of Approvals**

[This reflects the status of the option as it moves through the decision making and assessment process from conception to final recommendation.]