La Capra Associates

VELCO/CVPS
SOUTHERN LOOP PROJECT
DISTRIBUTED GENERATION STUDY

Technical Report

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Executive Summary

CVPS and VELCO have retained La Capra Associates to conduct a study of the cost and performance of Distributed Generation (DG) technologies that could potentially be effective resources, when combined, to address issues associated with the existing Southern Loop Transmission Facility. Briefly put, the scope of this study is to identify potential DG technologies, conduct an initial screening to determine which technologies are feasible as solutions to the issues with the Southern Loop, and to provide cost and performance parameters for feasible technologies.

We first identified nine DG technologies and nine fuel types that are commonly included when analyzing DG options. These are shown in the following table.

Technologies and Fuel Types

	Fuel Types								
Technology Types	Natural Gas	Distillate Fuel Oil	Landfill Gas	Biodiesel	Biogas	Biomass	Propane / LNG	Coal	Gasoline
Internal Combustion Engines	Y	Y	Y	Y	Y	N	Y	N	Y
Combustion Turbines	Y	Y	Y	N	Y	N	Y	N	N
Microturbines	Y	Y	Y	N	Y	N	Y	N	N
Conventional Boilers w/ STG	Y	Y	Y	Y	Y	Y	Y	Y	N
Fluidized Bed Boilers w/ STG	N	N	N	N	N	Y	N	Y	N
Fuel Cells	Y	N	Y	N	Y	N	Y	N	N
Wind	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Solar PV	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Hydro	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Each of the above technologies and fuel types were evaluated for their ability to effectively serve as an alternative to other solutions being considered to address reliability issues associated with the existing Southern Loop Facility. The fuel infrastructure in Vermont was assessed for the feasibility of delivering each of the fuel options. As a result of this process, we narrowed our list of DG options and fuel types to those shown in the table below.[1]

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[1] As described herein, certain technologies, like wind and solar PV, have not been determined to be a feasible DG option for resolving reliability problems on the Southern Loop. However, these technologies may nonetheless be

Feasible DG Options

Technology Types	**Distillate Fuel Oil**	**Landfill Gas**	**Biodiesel**	**Biogas**	**Biomass**	**Propane / LNG**
Internal Combustion Engines	Y	Y	Y	Y		Y
Combustion Turnbines	Y	Y		Y		Y
Microturbines	Y	Y		Y		Y
Conventional Boilers w/ STG					Y	Y
Fluidized Bed Boilers w/ STG					Y	
Fuel Cells		Y		Y		Y

We provide cost and performance parameters for each option listed in the above table. This includes emission data on each DG technology. CVPS will utilize this cost and performance data in evaluating whether DG should be a desirable component of the longer term plan to improve system reliability performance in the area served by the Southern Loop Transmission facility.

We note that this report focuses on available technologies that can be effectively deployed in the next few years to address current reliability concerns. There may be emerging technologies in the future that may help solve reliability problems on the Southern Loop that are not considered in this study. Should use of DG resources prove to be part of a cost-effective longer term solution to the Southern Loop reliability problem, further analysis may be warranted. At that time, the list of feasible DG options should be reconsidered to assure that all viable cost-effective technologies are taken into account in any implementation planning strategy.

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useful in meeting energy requirements to serve load or to diversify the mix of resources relied upon to meet Vermont's energy requirements.

I. Introduction

The existing Southern Loop transmission infrastructure is a 46 KV sub-transmission line operating in Southern Vermont. This line originates at the Vernon Road substation on the Southern end of the Vermont – New Hampshire border and terminates at the Woodford Road Substation in Southwestern Vermont. It traverses the northern portions of Bennington and Windham counties, connecting existing substations at North Brattleboro, Georgia Pacific, West Dummerston, East Jamaica, Londonderry, Rawsonville, Stratton, Bromley, Manchester, Wallace, Arlington, East Arlington, and South Shaftsbury. This sub-transmission line passes through the following towns: Brattleboro, Dummerston, Newfane, Townsend, Jamaica, Londonderry, Windham, Winhall, Manchester, Sunderland, Arlington, Shaftsbury, and Bennington. This 46 KV circuit is connected to Vermont's existing 115 KV system at Bennington and Brattleboro, and is fed entirely from the bulk transmission system. There is little or no existing generation along the route of the Southern Loop.

According to VELCO and CVPS, electric peak loads in the areas served by the Southern Loop have grown and usage of electric energy has grown significantly over the past two decades. This has caused loads to approach the capacity of the transmission infrastructure, and have greatly lessened the ability of the system to withstand system contingencies or equipment failures and facilitate scheduled maintenance. Current problems experienced by this system are heavy loadings and low voltages during high load periods coincident with contingencies.

CVPS and VELCO are exploring solutions to resolve these issues and improve the performance of the delivery system in Southern Vermont. We understand that a wide range of potential options are being considered, including:

- Aggressive expansion of Demand Side Management and Energy Efficiency programs targeted at customers served by the Southern Loop;
- Installation of synchronous condensers at the middle of the Southern Loop to improve voltage performance of the system;
- Add a 115 KV line as a supplement to the existing 46 KV line;
- Consideration of Distributed Generation technologies - to be targeted at utility and customer sites - that can relieve current reliability constraints and improve voltage performance.

Various combinations of the above options will yield resource configurations that will be analyzed by CVPS.

II. Distributed Generation Alternatives

VELCO and CVPS have retained La Capra Associates to conduct an assessment of Distributed Generation (DG) alternatives that could potentially be deployed to address some or all of the issues associated with the current Southern Loop facility. The scope of this assessment is to:

- Identify potential DG alternatives to be evaluated.
- Conduct an initial screening to determine which alternatives are applicable to the Southern Loop issues and the target geographic area.
- Develop detailed characteristics (including cost and performance data) of DG alternatives that appear realistic for helping to resolve the Southern Loop reliability concerns.
- Explore feasibility issues associated with actual deployment of leading DG alternatives.

It is important to note that La Capra's efforts in this study are focused only on DG alternatives that can serve as part of a solution to the reliability issues facing the Southern Loop transmission facility. In this report, we analyze DG options than can effectively serve as remedies to reliability issues on the Southern Loop delivery system, and can therefore (individually, or in combination with other resources) potentially displace or defer investments in transmission facilities. If a particular DG option is unlikely to satisfy reliability driven performance specifications, we remove it from consideration during the screening analysis. However, once a DG option passes the threshold criterion of being a reliable alternative or complement to new transmission facilities, there are other considerations (e.g., displacing higher cost sources of energy, reducing emissions, providing fuel diversity, or using renewable fuel sources) that might conceivably add to the justification for implementing certain DG resources. For example, the State of Vermont has passed Act 61, which creates the Sustainably Priced Energy Enterprise Development (SPEED) Program. This program represents a state-wide effort to encourage the development and implementation of renewable energy resources that are expected to cost less than or be more price stable than conventional supplies. If a particular DG resource can serve as both an alternative to new transmission and count as a new renewable resource under the SPEED program, there may be benefits or synergies that should be included in CVPS's analysis of alternatives and implementation planning.

We further note that this report does not address the issue of DG unit availability, or the relative reliability of DG options versus other components of the various resource configurations, such as transmission or DSM. This issues should be addressed by CVPS and VELCO during their evaluation of the resource configurations.

III. Amount and Location of DG Needed

VELCO and CVPS have estimated the approximate amount and approximate location of DG resources that could be required to serve as an effective and feasible alternative in their evaluation of potential solutions to the issues associated with the Southern Loop. We understand that this assessment is preliminary, and that it will be updated by VELCO and CVPS after La Capra has completed this study of DG options and the utilities' other consultants complete their assessment of DSM alternatives. The receipt of this preliminary estimate did assist La Capra in properly focusing on which DG alternatives should be considered.

In this report, we shall refer to the various combinations of DSM, DG, and transmission as resource configurations. In some resource configurations to be studied by VELCO and CVPS, no DG resources are assumed to be installed. These resource configurations consist of combinations of DSM and transmission upgrades. Other resource configurations feature levels of DG resources required that ranged from 21 MW to 105 MW, with varying amounts located at different places along the route of the Southern Loop.

Table 1 below summarizes the amount of peak load contribution and assumed location of DG resources required in order for DG alternatives to be part of an effective solution to the reliability issues on the Southern Loop. This table depicts only the quantity of DG included. In each resource configuration developed by CVPS, the MW and MWH contribution from DG resources is accompanied by varying amounts of DSM and implementation of specific transmission projects not shown here. For example, preliminary resource configuration #6 represents an all-DG solution, while #1 features substantial investments in DSM and transmission and therefore requires much less DG. The issues surrounding feasibility of specific DG options are discussed later in this report.

Table 1

DG Contained in Preliminary Resource Configurations

Location	#1	#2	#3	#4	#5	#6
Stratton MW	21	20	31	21	21	31
Bromley MW		5	7	6	6	9
Brattleboro MW				15	16	18
West Loop MW					17	21
East Loop MW					20	26
Total MW	**21**	**25**	**38**	**42**	**80**	**105**

Operating Hours

Table 2 provides the annual energy required from DG resources as estimated by CVPS for year 10 of the study for each DG resource configuration. The operating hours of DG resources vary significantly for this range of peak contribution. At the 21 MW and 25 MW levels, DG resources are needed approximately 153 hours per year (some hours at part-load output), representing deployment strictly in a peak shaving mode. On the other hand, CVPS estimates that at the 38 MW and 42 MW levels, DG resources would be required to operate 2,000 to 3,000 hours per year, representing a combination of peaking and intermediate or cycling modes. At the higher end of the range, in the 80 MW and 105 MW resource configurations, DG resources would be relied upon much more frequently, with at least some DG output required in more than 7,000 hours per year. This mode represents a combination of a small fraction of the DG capacity running round-the-clock, with substantial amounts of the DG capacity operating in intermediate and peaking modes. Overall, required capacity factors for DG resources are fairly modest, being well below the system average load factor.

Table 2

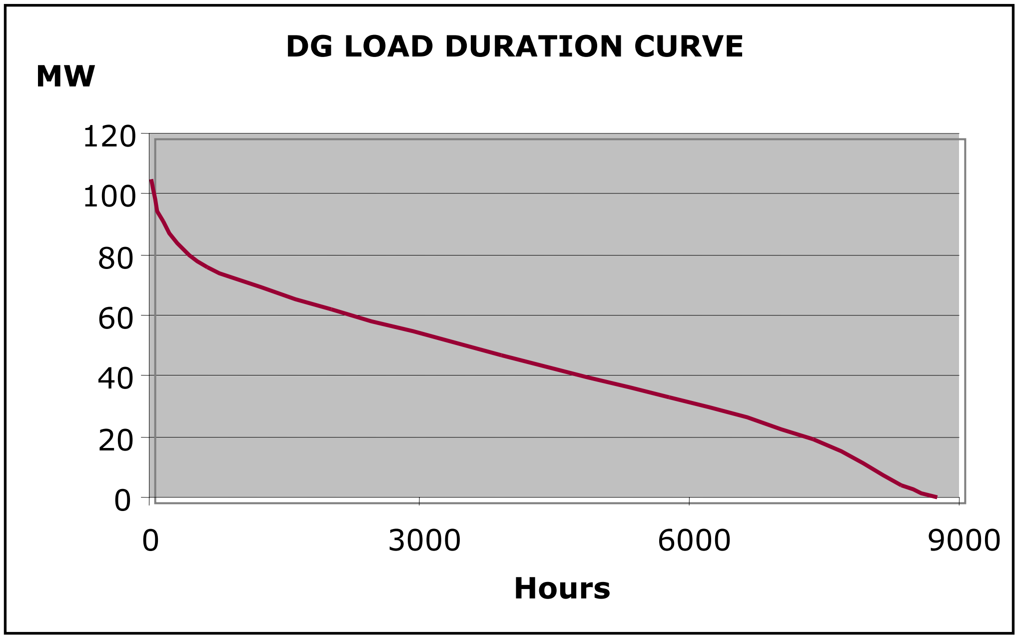
Energy Requirements for Potential Levels of DG

Resource Configuration	MW	MWH/year	Annual Capacity Factor
#1	21	1,533	1%
#2	25	325	<1%
#3	38	11,987	4%
#4	42	23,789	6%
#5	80	222,057	32%
#6	105	321,857	35%

Figure 1 provides the estimated operating hours and load duration curve for the 105 MW DG resource configuration for year 10 of the study.

Figure 1

Estimated Operating Hours for 105 MW "All-DG" Resource Configuration



According to CVPS, the peak usage for loads served by the Southern Loop facility occurs in the winter season late in the afternoon or early in the evening. To be effective as an alternative to transmission and energy efficiency options, the output of DG resources must have the ability to achieve a very high coincidence with the timing of the peak load. There are a couple of ways to achieve that coincidence. The first is to include DG options that are fully dispatchable. For these types of resources, their output can be scheduled by CVPS to be at full power when the system peak occurs. The other way is to include base load DG options that produce power during all hours of the day. In this situation, we can be confident that power will be produced when it is needed.

IV. DG Options

DG Options can be characterized by two generic categories. Customer-Based DG resources are installed on the customer side of the electric meter, and are typically sized to meet the needs of the individual customer. Grid-based DG resources are installed on the utility's side of the electric meter (i.e., connected directly to the transmission or distribution system), and the size is not constrained to the needs of a particular customer. These categories can be independent of ownership of the DG assets. Both grid-based and customer-based DG resources can be owned by the customer, the utility, or an independent third party assuming the appropriate terms can be agreed upon. This distinction becomes important during the implementation stage where actual sites are selected. In characterizing DG options in this report, we have not quantified any differences that may exist due to the ownership of the DG assets.

The following is a list of electric generating technologies that are frequently deployed as DG resources. These options come in various output sizes, as is discussed later in this report.

- Internal Combustion Engines / Reciprocating Engines
  - Spark Ignited
  - Compression Ignited / Diesels
- Combustion Turbines
- Microturbines
- Conventional Boilers with Steam Turbine Generators
- Fluidized Bed Boilers with Steam Turbine Generators
- Fuel Cells
- Solar Photovoltaic (PV)
- Wind
- Hydroelectric

Some of the above technologies, such as wind, solar, or hydroelectric, do not require the consumption of fuels to produce electricity. Others, such as fuel cells and microturbines, do require the consumption of fuels. Listed below are types of fuels that may[2] be utilized in one or more of the DG technologies.

- Natural gas
- Distillate fuel oil / diesel oil
- Landfill gas
- Biodiesel
- Biogas (via anaerobic digestion)
  - Cow manure
  - Farm waste
  - Sewerage
- Biomass (direct burn)
  - Farm / agricultural waste
  - Wood products (e.g., whole tree chips, sawdust)
  - Mill waste
  - Forest residue
  - Urban waste
- Propane / LNG
- Coal
- Gasoline

Some of the listed DG technologies are capable of utilizing more than one fuel. For example, combustion turbines can (with some modifications and/or fuel treatment) burn natural gas, propane / LNG, landfill gas, biogas, or distillate fuel oil. Table 3 provides a matrix of the fuel types that can be used in various technologies.

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[2] Note that not all of the fuels listed here are necessarily available at locations accessible to the Southern Loop. This will be discussed in the report section on Vermont's energy infrastructure.

Table 3

Technologies and Fuel Types

	Fuel Types								
Technology Types	**Natural Gas**	**Distillate Fuel Oil**	**Landfill Gas**	**Biodiesel**	**Biogas**	**Biomass**	**Propane / LNG**	**Coal**	**Gasoline**
Internal Combustion Engines	Y	Y	Y	Y	Y	N	Y	N	Y
Combustion Turnbines	Y	Y	Y	N	Y	N	Y	N	N
Microturbines	Y	Y	Y	N	Y	N	Y	N	N
Conventional Boilers w/ STG	Y	Y	Y	Y	Y	Y	Y	Y	N
Fluidized Bed Boilers w/ STG	N	N	N	N	N	Y	N	Y	N
Fuel Cells	Y	N	Y	N	Y	N	Y	N	N
Wind	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Solar PV	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Hydro	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

In the above table, biodiesel is excluded as a fuel for combustion turbines and microturbines. While it is theoretically possible for these units to utilize such a fuel, there is limited industry experience, and O&M costs are typically higher. Biodiesel tends to be better utilized in internal combustion engines. To the extent that emerging technologies mature such that their anticipated performance characteristics suggest that these conclusions should be altered, the list of viable alternative will need to be reconsidered as a part of any implementation strategy. Some of the above technologies are suitable for deployment in a combined heat and power (CHP) application, where thermal energy produced by a particular technology is captured rather than rejected, and is converted into useful energy products, such as steam or heat water. Such CHP applications are highly dependent upon the relationship between electric and thermal loads of the customer(s) being served by the facility.

In the next section of this report, we will summarize the infrastructure in Vermont for supplying these fuels.

V. Vermont Energy Infrastructure

In theory, many DG technologies that require fuel inputs can utilize several different types of fuels. In practice, these options are often limited by the actual availability of such fuel sources at relevant locations. This section discusses the current energy infrastructure in Vermont. We attempt to assess availability of sources for each of the above fuel types within the geographic purview of the Southern Loop facility. In a later report section that describes the initial screening process, we will utilize the information provided in this section.

Existing Power Plants

According to ISO-NE, Vermont[3] has 84 electric generating units with a total of 878 MW of installed capacity, as shown in Table 4 below. Of this total, approximately 55 MW are characterized as settlement only units, meaning that they are not bid into the ISO-NE Day Ahead Market, but simply receive the hourly market price. The vast majority of these units do not burn fossil fuels.

Table 4

Vermont Generating Units

Unit Type	No. of Units	MW
Distillate Fuel Oil	13	86
Jet Fuel Oil	1	29
Landfill gas	1	5
Nuclear	1	513
Biogas	1	0.275
Hydro	64	169
Biomass (direct burn)	2	75
Wind	1	1
total	84	878

The above statistics are for existing units connected to the electric grid and included in ISO-NE's October 2005 SCC Report. None of these units are located along the route of the Southern Loop. Smaller units connected to the customer side of the meter are not included. According to information from CVPS, there are only a few, small customer-connected units along the route of the Southern Loop, with an aggregate capacity of less than 2.5 MW.

Hydro

There are 64 hydroelectric units in Vermont with a total capacity of 169 MW. We understand that there is very little opportunity for economic development of hydroelectric capacity along the route of the Southern Loop. According to a system map of Vermont's electrical generating facilities, there are no existing hydroelectric facilities along or near the route of the Southern Loop. Therefore, hydroelectric generation does not seem to have the infrastructure to support new DG resources that could be alternatives to resolve the issues associated with the Southern Loop.

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[3] Note that Table 4 depicts only electric generating units located in the Vermont Standard Market Design (SMD) zone. There are six additional hydro units totaling 155 MW that are physically located in the State of Vermont, but are electrically connected to SMD zones in Massachusetts and New Hampshire.

Natural gas

The State of Vermont has one gas utility, Vermont Gas System. However, its facilities are located in Northwestern Vermont, and are far from the geographic area of the Southern Loop facility. There are no local facilities for the supply, transmission, or distribution of natural gas in Southern Vermont that would enable natural gas to be considered as a realistic option for fueling new DG resources on the Southern Loop. There is a natural gas radial supply to Hoosick, NY, which is 10 to 15 miles from Bennington. This system would need to be extended further into Southern Vermont to be useful.

Distillate fuel oil / diesel fuel oil

Vermont does not have any significant petroleum infrastructure, and relies upon railcar and tanker trucks for the delivery of its distillate fuel oil supply. However, distillate fuel oil is transportable and storeable, so long as there is access to highways, railroads, or thoroughfares. Vermont is already heavily dependent upon this fuel for purposes such as home heating.

Only 13 electric generating units in Vermont with a total capability of approximately 86 MW burn distillate fuel oil (DFO). CVPS owns only three of those, with a combined capability of approximately 30 MW and locations at Ascutney, Rutland, and St Albans. One other unit in Vermont, located at Berlin with a capability of 29 MW and owned by GMP, burns jet fuel. The CVPS generating unit closest to the Southern Loop is the Ascutney combustion turbine. The fuel supply for each of the three CVPS units is delivered by 7,500 gallon tanker trucks from out-of-state oil terminals, such as in Albany, NY. The type of fuel is conventional diesel, and is typically priced at market rates for the terminal facility plus an appropriate adder for delivery. On-site storage capacity is 300,000 gallons at Rutland, 250,000 gallons at Ascutney, and 10,000 gallons at St Albans.

According to EIA statistics, Vermont utilizes 5.4 million barrels per year of distillate fuel oil for non-transportation purposes, such as space heating or electric generation. If all of the required energy in the 105 MW DG resource configuration were fueled by DFO, it would use an estimated additional 600,000 barrels of distillate fuel oil per year, or about an 11% increase.

None of the existing generating units are located near the Southern Loop facility. Therefore, there appears to be little or no opportunity to piggyback fuel supplies for new DG resources onto fuel supply arrangements for existing generating units. However, this fuel can support a large number of potential DG technologies. The market for distillate fuel oil is relatively competitive, and there are some benchmarks or forward prices that can be relied upon for price forecasts. Given the transportability of distillate fuel oil and its existing use, we consider distillate fuel oil to be a viable source of fuel for DG resource configurations. Thus, distillate fuel oil can likely be considered a feasible fuel for DG alternatives as solutions to the Southern Loop issues.

Landfill Gas

There is currently one new electric generating unit in Coventry, Vermont fueled by landfill gas. This facility was commissioned in September 2005, and produces approximately 5 MW via three internal combustion engines. It is located far from the Southern Loop. Additionally, CVPS is the purchaser of the output from the landfill gas project located at the Windham County Solid Waste Management District Landfill in Brattleboro, Vermont. Current capacity of this facility is 0.5 MW.

Based upon customer information provided by CVPS, there does not appear to be any undeveloped landfill sites located on distribution circuits supplied by the Southern Loop facility. According to information available from the Waste Management Division of the Vermont Department of Environmental Conservation, there are two undeveloped landfill facilities located in towns traversed by the Southern Loop: the Burges Brothers facility in Bennington and the Shaftsbury Selectboard facility in Shaftsbury. There is another landfill facility in Wardsboro, but this appears to be too far from the Southern Loop to be able to serve as a resource for this study's purposes. Based upon the lack of landfill sites served by the Southern Loop and the existence of only two undeveloped landfills close to the target geographic area, landfill gas alone appears to be able to support only a very limited fraction of the considerable DG resources that will likely be required along the Southern Loop.

The use of fuels such as landfill gas or biogas requires additional gathering equipment and the gas is often contaminated with moisture, non-methane organic compounds and nitrogen. Pre-combustion conditioning or compression of the gas is sometimes necessary for proper operations. Furthermore, these fuels have reduced output for a given engine size due to their lower caloric value. Landfill gas typically has 45 to 55% methane with small amounts of oxygen, nitrogen, & non-methane organic compounds (NMOCs) and trace compounds. Typically the heat content of LFG is about 500 btu/scf.

However, to the extent that there are undeveloped landfill sites that are on the Southern Loop at locations where they can support even small levels of DG resources, these warrant consideration.

Biodiesel

Biodiesel is a fuel that is similar to distillate fuel oil that is made from the chemical breakdown of vegetable oil. It can be used as straight fuel or in a mixture with distillate fuel oil.[4] It is a relatively new resource, and the Energy Policy Act of 2005 provides incentives to producers for the increased production of biodiesel. Several projects that utilized biodiesel in power generation were undertaken in California in 2001 and 2002, but most have discontinued the use of biodiesel. It is increasingly common in generators at U.S. national parks, but for generators smaller than 100 kW and using B20 or B50 biodiesels.

There are several biodiesel distributors in Vermont, specifically in Williston, Milton, Winooski, and Shoreham. None of these is near the route of the Southern Loop facility. Biodiesel fuel tends to be more expensive than distillate fuel oil, although biodiesel is a renewable resource. Also, B100 may encounter problems with storage in the cold temperatures associated with Vermont winters. However, biodiesel supplies can be transported to locations on the Southern Loop where they can support DG resources, much in the same way distillate fuel oil is supplied. B20 and B5 are the products most likely to be feasible because these fuels represent a good balance between cost and environmental performance and fuel handling issues during cold weather are mitigated. Therefore, biodiesel should be considered as a viable fuel for some amount of DG resources. However, from the perspective of analyzing the cost-effectiveness of DG options as a solution to the issues associated with the Southern Loop, B20 and B5 biodiesel are likely to perform similarly to distillate fuel oil.[5]

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[4] B100 biodiesel is 100% biodiesel, while B20 is 20% biodiesel and 80% distillate and B5 is 5% biodiesel and 95% distillate.

[5] There may be added renewable fuel value for a portion of the biodiesel under Vermont's SPEED program, as the rules have not yet been finalized.

Biogas via Anaerobic Digestion

Anaerobic digestion is the process of converting organic matter into gaseous products that contain energy and solid products that can be composted or recycled. Typical organic feedstock includes cow manure, farm waste, and sewage.

Vermont has many dairy farms, and therefore many cows. CVPS has established its CVPS Cow Power™ program, where customers can get some or all of their electricity from farm generation.[6] To participate in this program, electricity customers pay CVPS their normal retail rates plus an additional 4 cents per KWH for a supply from renewable resources. CVPS pays dairy farms that produce electricity from cow manure 95% of the hourly market price for the electricity plus the additional 4 cents per KWH collected from customers for the attendant renewable energy certificates or "RECs". To date, Blue Spruce Farms has installed the equipment to produce a maximum output of 275 KW and approximately 1.7 million KWH of electricity per year from cow manure.

Anaerobic digestion is typically economical for dairy farms with a herd size more than 500. [7] While there are over 1,400 dairy farms in Vermont, less than 3% of them have more than 500 cows. [8] Newer digester technology may improve this, but the timing is uncertain. It has been estimated that the state-wide potential for power from cow manure is approximately 28 MW. [9] Within Bennington and Windham counties, there are approximately 56 dairy farms, but none appear to be of sufficient size for current digestor applications within the area served by the Southern Loop. While the CVPS Cow Power program has merit as a source of indigenous energy supply, it appears to have limited capability to meet the needs of the Southern Loop.

Information available from the Waste Management Division of the Vermont Department of Environmental Conservation indicates that there are 24 composting facilities in Vermont, but that none are located within the geographic area of the Southern Loop Facility. There are no composting facilities listed among the customers served by the Southern Loop. Therefore, composting sites were not deemed to be available as sources of organic matter for anaerobic digestion. The Bennington Waste Water Treatment Facility (WWTF) does utilize a very small amount of methane for process load purposes, but currently produces no electricity.

In summary, industry information suggests that along the Southern Loop, the potential for electricity generation fueled by biogas from anaerobic digestion is quite limited. While it would be worthwhile for CVPS to explore any potential biogas facilities on the Southern Loop that may ultimately be identified, any such facilities would likely play only a limited role in meeting the needs of the Southern Loop.

Biomass / Solid Waste

Vermont currently has two large facilities that produce electricity from biomass. The McNeil facility in Burlington produces approximately 54 MW from wood waste (along with whole tree chips), with natural gas as a secondary fuel. The Ryegate facility produces about 20 MW and also uses wood as a fuel input. Neither of these facilities is located near the Southern Loop. Wood is also used as a significant source for

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[6] If insufficient farm generation is not available, CVPS will utilize other forms of renewable energy or purchase RECs to meet customer demands.

[7] See report on the Vermont Methane Pilot Program at www.biomasscenter.org.

[8] Bob Parsons, University of Vermont, Professor of Farm Management

[9] See Table 5-1 of 2005 Vermont Energy Plan. Potential for all other feedstocks is less than 2 MW.

space heating and some thermal processes. For example, Cersosimo Lumber in Brattleboro uses wood-fired boilers for process loads and space heating, and does not currently produce electricity.

The majority of presently available wood fuel in Vermont is a by-product of some other business activity, such as sawmills or logging. New sustainable whole tree chipping activities dedicated to the supply of a significant wood-fired power plant could potentially be developed as well, although the substantial financial commitments of long-term contracts would likely be required. The most recent Vermont Comprehensive Energy Plan was published in 1998. At that time, the estimate for the potential for additional electric capacity from wood was approximately 40 MW. An updated Comprehensive Energy Plan is in preparation, so there may be a better estimate available soon. We are aware of one new wood-fired project being discussed for the Rutland area; this would not be close to the Southern Loop. Typically, wood fuel supplies can be effectively transported by railcar or truck over distances up to 50 miles. In summary, there is technical potential for additional wood-fueled DG resources.

A new wood-fired facility could be considered a SPEED resource under Vermont's Act 61. Under Act 61, renewable energy is defined as energy produced using a technology that relies upon a resource that is being consumed at a harvest rate at or below its natural regeneration rate. Agricultural and silvicultural wastes are the only forms of solid wastes that are considered renewable. To qualify as a SPEED resource, a facility must be located in Vermont and should be certified by the Vermont Public Service Board. It is also possible that a new biomass facility could qualify as a renewable resource in neighboring states, and the renewable energy credits (RECs) could be sold to states that have Renewable Portfolio Standards (RPS). In either situation, there would be value in such facilities beyond whatever benefits the facility could provide to the Southern Loop. These additional benefits could reduce the net cost of such projects.

Municipal solid waste can also be utilized in refuse-to-energy facilities. According to information available from the Waste Management Division of the Vermont Department of Environmental Conservation, there are two recycling facilities and five transfer stations in near proximity to the route of the Southern Loop. The recycling facilities are the Windham SWMD and the Zaluzny Excavating sites. Transfer stations exist at least at Brattleboro Salvage in Brattleboro, and in Jamaica, Londonderry, Townsend, and Stratton. We do not have information on the size of these facilities, nor have we analyzed the suitability of using the waste at these facilities as a fuel to generate electricity. To the extent that there is technical and economic potential to deploy waste at these sites, this option should be included. However, municipal solid waste fuel would not be considered a SPEED resource and is often perceived to have numerous environmental, emissions, and NIMBY issues.

Therefore, biomass fuels, especially wood and wood waste, should be preferred over municipal solid waste. These fuels are available in Vermont and can be transported relatively effectively, and therefore should be considered as a viable fuel resource for DG technologies. The specific availability of wood fuel in close proximity to the Southern Loop is not entirely clear. To the extent that there are biomass fuel supplies in the area of the Southern Loop where they can support DG resources, these should be evaluated by CVPS as a part of any implementation strategy.

Propane / LNG

There are no LNG facilities in Vermont. Propane does hold a 14% share of the home heating market, and Vermont consumes about 68 million gallons per year. [10] However, it is not typically used in electric generation due to its value as a home heating and recreational fuel. On a $ per mmBTU basis, propane is

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[10] EIA statistics for Vermont

more expensive than distillate fuel oil. Environmentally, propane is a cleaner fuel, producing fewer emissions than distillate fuel oil. The Propane Gas Association of New England lists 57 dealers in Vermont, but only six appear to be within the target geographic area of the Southern Loop facility. Propane can be transported and stored on-site, and therefore, we will include this fuel resource in our analysis.

If all the required energy in the 105 MW DG resource configuration was supplied by DG resources fueled by propane, it would represent incremental consumption of over 39 million gallons, or a 57% increase in usage over current annual consumption in the state. As a result, it is likely that there would be a very significant increase in propane deliveries needed to support a significant level of DG resources burning this fuel. Propane dealers would include any increased delivery costs in the price of the propane they deliver. While we have not specifically forecast price increases, the price does need to remain competitive with other competing fuels, such as distillate fuel oil.

DG resources utilizing propane would require on-site storage, to protect against the potential that deliveries could be temporarily curtailed due to severe winter weather. A 1 MW DG resource fueled by propane that operates eight hours in a winter day consumes about 1,000 gallons of propane. If 15 days worth of fuel is stored on site, each 1 MW resource would require a 18,000 gallon tank.[11] Such a tank is a cylinder approximately 9 feet in diameter and 41 feet in length. A 30-day on-site supply, which is typical for utility power plants, would require twice as much propane. The following picture in figure 2 shows a typical propane storage tank farm.

Figure 2

Propane Storage Tank Facility

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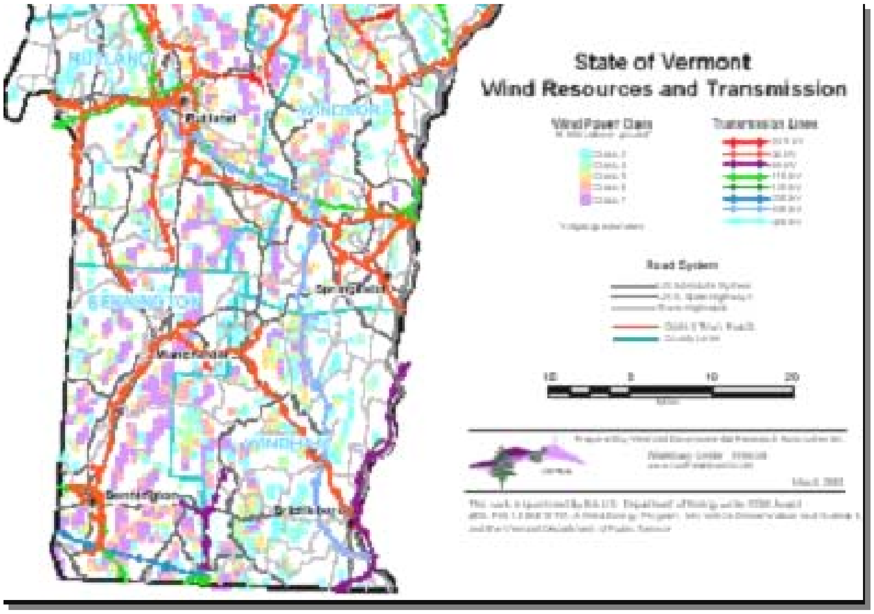
[11] Propane tanks are normally filled to a maximum level of 85% of capacity.

Wind

There is a 6 MW wind generating facility at Searsburg, VT that is owned by GMP. Because of the intermittent nature of the output of wind turbines, this generating facility is listed in table 4 as providing 1 MW of capacity. According to the map provided in figure 3, there are some locations in the area of the Southern Loop that appear to have good potential for wind generation. With the level of wind speeds and existence of ridgelines, Vermont appears to have the potential for cost-effective deployment of wind energy sources.

Figure 3

Wind Potential in Vermont



Because of this potential, several wind projects are planned or under consideration in Vermont. They include:

- The expansion of the existing Searsburg Facility (30 to 45 MW)
- UPC Project in Sheffield (35 to 45 MW)
- East Haven Wind Farm (6 to 8 MW)
- Lowell Wind Project in Eden, Lowell, and Irasburg (20 to 39 MW)
- Equinox Wind Farm in Manchester (9 MW)
- Glebe Mountain Wind Project in Londonderry (48 MW)[12]
- UPC Project in Windham, Grafton, & Townshend (size not yet determined)

The last three listed above are in reasonable proximity to the Southern Loop transmission line. CVPS has recently announced a 20-year agreement to purchase the output of the Glebe Mountain Wind Project, but the project is currently on hold.

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[12] Note that the developer of the Glebe Project has delayed filing for needed permits due to perceived regulatory uncertainty associated with the development of wind resources in Vermont.

While valuable as a renewable energy resource that can reduce dependence on imported fossil fuels and help stabilize energy costs, wind energy generators have relatively low capacity factors, are not dispatchable, and their output cannot be readily scheduled or counted upon to address conditions on the transmission system. Thus, even if the last three facilities listed above were constructed, it is unlikely that they would effectively mitigate or defer the need for new transmission facilities to resolve existing reliability problems. In addition, there is considerable uncertainty around permitting wind facilities. Therefore, there is considerable uncertainty about wind's ability to serve as an effective solution to transmission issues.

Furthermore, many wind generating units are induction machines which require reactive power from the system to operate According to CVPS, given the current performance level of the Southern Loop transmission facility, it may not be desirable to deploy resources that require a significant amount of reactive power because reactive power supplies are already inadequate. To address existing issues, CVPS is considering installing a 30 MVAR synchronous condenser at Stratton at a cost of approximately $10 million to increase the supply of reactive power and improve voltage performance of the system. Adding additional reactive power supplies would increase the cost of a wind DG option and create operational logistics issues. However, newer wind generating units can strengthen a weak electric grid. For example, GE has developed its WindVAR control system that can reduce or eliminate the need for additional capacitors. Thus, if wind generation does become a feasible option for the Southern Loop, its implementation and its impact on the system should be studied carefully.[13]

Solar PV

There are currently three customer sites in the target geographic area where solar energy facilities totaling about 8 KW have been installed. Similar to wind, solar energy can be a valuable energy resource that can reduce dependence on imported fossil fuels. However, solar energy generators are not dispatchable, and their output cannot be readily scheduled to address conditions on the transmission system. The timing of the peak load in the targeted geographic area is late afternoon or early evening in the winter time, when solar energy facilities would not be producing significant power. Therefore, there is considerable uncertainty about solar energy's ability to serve as an effective solution to transmission issues.

Coal

There are no coal-fired electric generating facilities in Vermont, and the State utilizes virtually no coal for any purpose. The State lacks sufficient infrastructure to support development of new coal-fired generation sources. There are existing rail lines that support shipments of heavy products for OMYA in Florence, VT. The heavy product shipments from OMYA pass through rail facilities in Rutland, and then out of the area. These same rail facilities are connected to lines to traverse the western edge of Vermont from Rutland down to North Bennington. These lines are currently used for infrequent freight deliveries between Rutland and North Bennington, and it is uncertain if these facilities can support coal deliveries needed to fuel electric generators. Depending upon the specific location of coal-fired DG resources, expansion and upgrade of these rail lines might support such resources. Feasible coal-based alternatives are likely to be too large, in terms of MW, to effectively function as a DG resource in the size ranges needed to address issues associated with the Southern Loop. Permitting a new coal facility, albeit a small one, would be very difficult. For these reasons, we conclude that coal-based generation options do not warrant consideration in this analysis.

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[13] We are advised by CVPS that the Company is encouraging development of new small wind and solar projects as a part of Vermont Small Wind and Solar Fund activities are supported, in part, by CVPS contributions.

Gasoline

Gasoline can be used in some DG options. Compared to distillate fuel oil, it is a far less desirable fuel. Distillate fuel oil is less volatile, and can be used in more DG options. Based upon an assessment of current forward prices, distillate fuel oil is less expensive than gasoline on a dollars per mmBTU basis. Delivery mechanisms are approximately the same in Vermont. Because of this, we will not give any further consideration to gasoline as a fuel for DG. If it becomes desirable to examine a specific project, a more detailed analysis will be performed at that time.

VI. Initial Screening of Alternatives

The purpose of this section is to conduct an initial qualitative screening of DG options. In performing this assessment, we will examine both fuel and technology types.

First assessing the availability of fuels, we conclude that natural gas should not be considered because there is no infrastructure to supply it within the target geographic area. Coal should also be excluded because it is not currently utilized as a fuel in Vermont, and it has environmental issues associated with permitting and implementation. Also, coal-fueled technologies typically are economic at higher capacity factors and larger unit sizes than needed for the Southern Loop. Gasoline is excluded because of its undesirability as a fuel for electric generating units and its value as a transportation fuel.

Distillate fuel oil and propane are viable fuel options for several DG technologies, and will be included. The availability of propane should be examined more closely during implementation. DG resources fueled by propane have performance and cost characteristics similar to those fueled by natural gas. Landfill gas, biodiesel, biogas, and biomass are available only in limited amounts, and should be included to contribute what they can.

In assessing technology types, hydro units are excluded because of the lack of undeveloped sites. Solar PV and wind DG resources are excluded because they are not dispatchable and their output is not reliably coincident with the peak load or resolution of identified reliability problems. While it is theoretically possible to install energy storage systems to ensure that the output of these technologies is available at peak times, such storage systems are typically not feasible in the 21 to 105 MW size range required by DG options for the Southern Loop. To the extent that energy storage systems are feasible, they are very expensive to deploy, and are likely not economic.

Conventional steam boilers or fluidized bed boilers coupled with steam turbine generators are typically best suited for higher capacity factors and larger sized units than is required of DG options for the Southern Loop facility. Small DG applications below 5MW using these technologies may not be commercially feasible.[14] For distillate fuel oil, landfill gas, biodiesel, and biogas, other technologies such as internal combustion engines, combustion turbines, and microturbines are superior from a cost and performance viewpoint. However, steam-based technologies are the only ones listed that can effectively utilize biomass as a fuel, since Vermont has sufficient indigenous resources to fuel these technologies at some level. Based on this assessment, we include these technologies only for biomass fuels.

Table 5 summarizes the DG technologies and fuel types that will be considered further.

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[14] Larger units such as the 20 MW Ryegate facility are commercially feasible.

Table 5
Feasible DG Options

Technology Types	Distillate Fuel Oil	Landfill Gas	Biodiesel	Biogas	Biomass	Propane / LNG
Internal Combustion Engines	Y	Y	Y	Y		Y
Combustion Turnbines	Y	Y		Y		Y
Microturbines	Y	Y		Y		Y
Conventional Boilers w/ STG					Y	Y
Fluidized Bed Boilers w/ STG					Y	
Fuel Cells		Y		Y		Y

In ensuing sections of this report, we will provide detailed performance and cost parameters for these selected technologies and fuel types.

VII. Emissions Assessment for Distributed Generation Options

The scope of this analysis focuses on distributed generation (DG) options to be located along the Vermont Southern Loop transmission area. The emissions assessment includes nitrogen oxide (NO_x), sulfur dioxide (SO_2), and carbon monoxide (CO). Emissions for distributed generation are highly dependent on the technology, fuel choice, and control equipment selected. We have chosen to provide a select list of technologies and fuel choices without emissions control retrofits in most cases, because post-process emissions controls tend to add 10-20% to the cost of a project.

Technologies

The technologies involving combustion of fuels will have greater emissions than fuel cells. We focused on technologies that are suitable and practical for distributed generation applications such as internal combustion engines, gas turbines, microturbines, steam turbines with fluidized bed and stoker boilers, and fuel cells. Also, renewable generation from solar and wind are emission-free and thus were also excluded from this assessment.

Fuels

The fuels themselves will dictate how much emissions are to be expected, with distillates such as diesel and heating oil having 10-20 times higher NO_x emissions than natural gas and other gaseous fuels. However, it is our understanding that natural gas is not available in the study region and other gaseous fuels (propane) are limited in supply. We have included technologies that use natural gas but assume that propane is likely burned in its place. With the new diesel engines, their emissions ratings are based on the assumption that low-sulfur diesel (i.e., 0.3% sulfur content) is burned, thus reducing SO_2 emissions to negligible levels.

Biodiesel is a plant-derived fuel that has similar characteristics to diesel and can easily substitute for diesel from 5%-100%, provided certain adjustments are made to fuel handling and storage. The net benefit is proportional to the percentage of biodiesel used in the mix. The emissions rates are not reflected in the chart below because the emissions benefits would be dependent on the selected technologies and percentage of fuel substitution. For a 100% biodiesel substitution (B100), SO_2 would be completely eliminated while CO would be reduced by about half. On the other hand, NO_x emissions actually increase by 10%. Despite the major emissions reductions with B100, it does not appear economically feasible to use 100% biodiesel in combustion engines because of the higher cost of the fuel and special fuel handling, maintenance, and storage required. A mix of biodiesel and diesel (B5 or B20) may provide a good balance between cost and emissions reduction.

Renewable fuels such as landfill gas, biogas from anaerobic digesters, and solid biomass feedstock have varying degrees of contaminants and moisture content in their fuel streams and, therefore, the related emissions and efficiencies are highly dependent on the fuel conditioning step prior to combustion. Furthermore, there are emissions related to the collection of these renewable fuels that may contribute to higher overall emissions, although in this report, we focus only on direct emissions. We have included some representative emissions rates for these renewable fuels, but the range may well be much wider. Additionally, there are projects, such as the Essex Junction Wastewater Treatment facility that blends the methane output from its anaerobic digesters with natural gas to provide peaking capability.

For biomass projects, emissions will vary widely based on biomass fuel type, biomass facility size and application, and boiler type. Generally, however, biomass will have minimal SO2 emissions, and may be considered carbon neutral, if the biomass fuel type is sustainable. Due to the specifics of the combustion process, fluidized bed applications will generally have lower emissions than stoker boiler applications, though control technologies are available that bring stoker emissions to levels comparable to fluidized bed applications.

Emissions Controls

All these emissions can also be addressed through pre- or post-process controls, though they may add 10-20% to the cost and operations of the generators. For the most part, the list we are providing does not include these controls extensively because many of the newer models meet EPA standards and are configured for low emissions without controls, though sacrificing efficiency in some cases. We do include the difference in emissions as a result of different calibrations of the combustion chamber and the use of a three-way catalyst (TWC) in rich burn configurations. For reference, catalytic oxidation can reduce CO by about 90% and selective catalytic reduction (SCR) can mitigate NOx by 80-90% depending on the design specifications.

Table 6
Summary of Emissions for Select Technologies and Fuels

Generation	Detailed Technology	Size	Fuel	NOx (g/kWh)	SO2 (g/kWh)	CO (g/kWh)	Notes on Control Technology
Microturbine	Capstone Microturbine	30 kW	Natural Gas (Propane)	0.12	negligible	0.34	No Nox Control
Fuel Cell	Fuel Cell	0.2 MW	LFG	0-0.2	N/A	N/A	No Nox Control, depends on pre-combustion treatment
Gas Turbine	Gas Turbine	>3 MW	LFG	0.2-1.0	N/A	N/A	No Nox Control, depends on pre-combustion treatment
ICE	Spark Ignition	<3 MW	LFG	0.6-3.7	N/A	N/A	No Nox Control, depends on pre-combustion treatment
ICE	Spark Ignition	100 KW	Anaerobic Digester Gas	5.5	10.4	26. 3	No Nox control, fuel input is not conditioned (no moisture or sulfur removal)
ICE	Spark Ignition	<2 MW	Natural Gas (Propane)	0.11	negligible	0.45	Rich burn with Three Way Catalyst (TWC) Control
ICE	Spark Ignition	<2 MW	Natural Gas (Propane)	0.70	negligible	3.20	Lean Burn for Low Nox/High CO without Controls
ICE	Spark Ignition	<2 MW	Natural Gas (Propane)	2.50	negligible	2.00	Rich Burn/Higher efficiency without Controls
ICE	Traditional Diesel Engine	100 kW-10 MW	Diesel	7.0-18.0	0.2 [15]	0.2	No NOx Control
ICE	Traditional Diesel Engine	100 kW-10 MW	Heavy Oil	12-20	1.4	4.2	No NOx Control
ICE	EPA Tier II Diesel Engine	500 kW	Low Sulfur Diesel (0.5% Sulfur)	2.1-4.5	0	0.23-0.35	Lean Burn without Controls, designed to meet EPA Tier II
ICE	EPA Tier II Diesel Engine	2 MW	Low Sulfur Diesel (0.5% Sulfur)	4.1-5.8	0.11-0.13	0.26-0.48	Lean Burn without Controls, designed to meet EPA Tier II
Gas Turbine	Gas Turbine	18 MW	Natural Gas (Propane)	0.44	negligible	0.29	Dry Low Emissions Configuration
Gas Turbine	Gas Turbine	6.5 MW	Natural Gas (Propane)	0.52	negligible	0.64	Dry Low Emissions Configuration
Gas Turbine	Gas Turbine	1.4 MW	Natural Gas (Propane)	0.37	negligible	0.80	Dry Low Emissions Configuration

N/A indicates data was not available for the emissions.

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[15] Greatly dependent upon the qualities of the fuel burned.

VIII. Cost and Performance Parameters

In the following sections of this report, we provide capital cost, operating cost, and unit performance information for DG options have that passed out initial screening. The information contained in these sections of this report is based upon manufacturers' specifications, industry information, literature searches, and our own experience in evaluating generation options.[16]

In most instances, we provide a single estimate of a particular cost parameter. This should be considered to be a typical number. We acknowledge that such costs can vary significantly by location and site. If site specific assessments are to be conducted in the future, these cost estimates would have to be further refined.

Finally, direct capital cost estimates do not include some cost categories, such as site preparation, permitting, fuel handling, and contingencies. For each technology, we have included an adder to account for such items, which are frequently called "soft costs". These generic adders are based upon our industry experience, but are not specific to any particular site or area within Vermont or the area served by the Southern Loop transmission facility. In developing real DG projects, these costs can vary greatly according to the site and technology chosen, and should be refined further if a particular location is to be evaluated.

Internal Combustion Engines

Reciprocating or internal combustion engines ("ICEs") start quickly, follow load well, have good part-load efficiencies, and generally have high reliabilities. In many cases, multiple reciprocating engine units are combined at one facility for operational flexibility. ICE's have higher electrical efficiencies than gas turbines of comparable size, and thus lower fuel-related operating costs. In addition, the total installed costs of reciprocating engine generators are generally lower than gas turbine generators up to 3-5 MW in size. Reciprocating engine maintenance costs are generally higher than comparable gas turbines.

The focus for this evaluation should be on 1 MW and 5 MW diesel engines burning low-sulfur diesel, since the region is unable to receive natural gas through pipelines.

Types of Engines

There are two basic types of ICEs – spark ignition (SI) and compression ignition (CI). Spark ignition engines (Otto-cycle) for power generation use natural gas as the preferred fuel, although they can be set up to run on propane, gasoline, or landfill gas. Compression ignition engines (often called diesel engines) operate on diesel fuel or heavy oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas with a small amount of diesel pilot fuel.

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[16] As emerging technologies are commercialized, the information contained in this report on unit cost and performance can be updated.

Diesel engines have historically been the most popular type of reciprocating engine for both small and large power generation applications. However, diesel engines are increasingly restricted to emergency standby or limited duty-cycle service because of air emission concerns. Consequently, the natural gas-fueled SI engine is now the engine of choice for the higher-duty-cycle stationary power market (over 500 hr/yr).

Engines are further categorized by crankshaft speed (rpm), operating cycle (2- or 4-stroke), and whether turbo-charging is used. Typically, smaller engines operate at high speeds while larger units operate at lower speeds. High-speed diesel engines (1,200 rpm) are available up to about 4 MW in size. Low speed diesels (60 to 275 rpm) are available as large as 65 MW.

Electric efficiency of engines improves with increases in size. Natural gas engine efficiencies range from about 31% (HHV) for small engines (<50 kW) to 46% (HHV) for the largest high performance, lean burn engines. Tuning for low NOx typically results in a sacrifice of 1 to 1.5 percentage points in electric generating efficiency from the highest level achievable. For diesel engines, efficiency levels increase with engine size and range from about 30% (HHV) for small high-speed diesels up to 42 to 48% (HHV) for the large bore, slow speed engines.

Fuel Options

Natural Gas Spark Ignition Engines: Natural gas is the predominant spark ignition engine fuel used in electric generation and CHP applications. Other gaseous and volatile liquid fuels, ranging from landfill gas to propane to gasoline, can be used with the proper fuel system, engine compression ratio and tuning.

The use of fuels such as landfill gas or biogas requires additional gathering equipment and the gas is often contaminated with moisture, non-methane organic compounds and nitrogen which would require pre-treatment of the fuel stream. Typically the heat content of LFG is about 500 btu/scf. Biogas can have even lower heat content as there may be more moisture from anaerobic digesters.

Diesel Engines: Compression ignition diesel engines are among the most efficient simple-cycle power generation options on the market. High-speed diesel engines generally require high quality fuel oil with good combustion properties. No. 1 and No. 2 distillate oil comprise the standard diesel fuels. Low sulfur distillate is preferred to minimize SO2 emissions. High-speed diesels are not suited to burning oil heavier than distillate. Heavy fuel oil requires more time for combustion and the combination of high speed and contaminants in lower quality heavy oils cause excessive wear in high-speed diesel engines. Many medium and low speed diesel engine designs burn heavier oils including low grade residual oils or Bunker C oils. Biodiesel consisting of a mix of 5-20% biodiesel and remaining being conventional diesel is an alternative fuel for diesel engines.

CHP Applications

Recovered heat is generally in the form of hot water or low pressure steam (<30 psig). The high temperature exhaust can generate medium pressure steam (up to about 150 psig), but the hot exhaust gas contains only about one half of the available thermal energy from a reciprocating engine. Some industrial CHP applications use the engine exhaust gas directly for process drying. Generally, the hot water and low pressure steam produced by reciprocating engine CHP systems is appropriate for low temperature process needs, space heating, potable water heating, and to drive absorption chillers providing cold water, air conditioning, or refrigeration.

Installed Costs

The basic genset package consists of the engine connected directly to a generator without a gearbox. A standard generator package consists of the engine, generator, frame, control system, fuel system, radiator, fan, and starting system. Additional components can be added depending on the special needs of the system. Essentially all modern engines above 300 kW are turbocharged to achieve higher power densities. A turbocharger is a turbine-driven intake air compressor.

The smaller engines are skid mounted with a basic control system, fuel system, radiator, fan, and starting system. Some smaller packages come with an enclosure, integrated heat recovery system, and basic electric paralleling equipment. The total plant cost consists of total equipment cost plus installation labor and materials (including site work), engineering, project management (including licensing, insurance, commissioning and startup), and financial carrying costs during the 6 to 18 month construction period.

Costs such as site preparation, permitting, fuel handling, and contingencies are not included. We have included a 10% adder to the costs shown below to arrive at total project costs.

Maintenance

Maintenance can be either done by in-house personnel or contracted out to manufacturers, distributors, or dealers under service contracts. Many service contracts now include remote monitoring of engine performance and condition and allow for predictive maintenance. Service contract rates typically are all-inclusive, including the travel time of technicians on service calls.

Recommended service is comprised of routine short interval inspections/adjustments and periodic replacement of engine oil and filter, coolant and spark plugs (typically 500 to 2,000 hours). An oil analysis is part of most preventative maintenance programs to monitor engine wear. A top-end overhaul, generally recommended between 8,000 and 30,000 hours of operation, entails a cylinder head and turbocharger rebuild. A major overhaul after 30,000 to 72,000 hours of operation involves piston/liner replacement, crankshaft inspection, bearings, and seals.

Table 7

Type	Sizes (kW)	Est'd Install Cost ($/kW)	Est'd Total Cost ($/kW)	CHP Cost ($/kW)	CHP Output (mmbtu/ hr)	Full Load Heat Rate (btu/ kWh)	Effcy	Var O&M ($/ MWh/ year)	Fixed O&M ($/kW-year)
Spark Ignition	300	1,300	1,430	225	1.5	11,000	31%	17	6
	800	1,200	1,320	110	3.5	10,200	33%	13	5
	3,000	1,100	1,210	85	11.1	9,500	36%	13	2
Diesel Engine	500	1,200	1,320	170	2.2	10,200	33%	17	6
	2,000	1,100	1,210	90	7.4	9,500	36%	13	3

(heat rate and efficiency for HHV)

All costs above in $2006

Manufacturers

Caterpillar
Coleman Powermate
Cummins
Daihatsu Diesel
Daimler Chrysler Power Systems
Detroit Diesel
Deutz
Electrical Generating Systems Association
Elliott Turbo
Engine Manufacturers Association
Fairbanks Morse Engine
FG Wilson
Finning
Ford Power Products
GE Power Systems
Generac
Genergy
Genset
Hess Microgen
Honda Power Equipment
Ingersoll-Rand
John Deere Power Systems
Kawasaki
Kohler Power Systems
MAN B&W
Mitsubishi Heavy Industries
Perkins
Pramac Group
Rolls-Royce
Same Diesel
SDMO
Taiyo Electric
Vericor Power Systems
Wartsila
Waukesha
Westac Power

Combustion Turbines

Gas turbine systems operate on the thermodynamic cycle known as the Brayton cycle, where the expansion of air through a turbine powers a compressor to generate electricity. Combustion turbines produce high-quality heat, much higher than that produced by ICE's, which can be used to generate steam for on-site use or for additional power generation (combined-cycle configuration). Combustion turbines can be set up to burn natural gas, a variety of petroleum fuels or can have a dual-fuel configuration. Gas turbine emissions can be controlled to very low levels using water or steam injection, advanced dry combustion techniques, or exhaust treatment such as selective catalytic reduction (SCR). Maintenance costs per unit of power output are among the lowest of DG technology options. Low maintenance and high-quality waste heat make combustion turbines an excellent match for industrial or commercial CHP applications larger than 5 MW. Technical and economic improvements in small turbine technology are pushing the economic range into smaller sizes as well.

Combustion turbines range in size from 500 kW to 250 MW, but those for customer-sited generation or distributed generation are typically 500 kW to 40 MW. For the purposes of this DG study, the focus will be on units below 20 MW.

Types of Turbines

Aeroderivative: Aeroderivative combustion turbines for stationary power are adapted from their jet and turboshaft aircraft engine counterparts. While these turbines are lightweight and thermally efficient, they are usually more expensive than products designed and built exclusively for stationary applications. The largest aeroderivative generation turbines available are 40 to 50 MW in capacity. Many aeroderivative combustion turbines require a high-pressure external fuel gas compressor. Aeroderivative combustion turbines offer quick-start capability of 10-minutes to full power, and are typically well suited to load-following duty.

Industrial: Industrial or frame combustion turbines are exclusively for stationary power generation and are available in the 1 to 250 MW capacity range. They are generally less expensive, more rugged, can operate longer between overhauls, and are more suited for continuous base-load operation with longer inspection and maintenance intervals than aeroderivative turbines. However, they are less efficient and much heavier. Industrial combustion turbines often do not require an external fuel gas compressor.

Fuel Options

The combustion turbines are typically designed to run on natural gas. Clean liquid fuels, such as distillate fuel oil, are also suitable for use in combustion turbines, but special combustors developed by some gas turbine manufacturers that can handle cleaned gasified solid and liquid fuels are incorporated. These special combustors were developed principally for large combustion turbines and are not found on small combustion turbines. Such smaller units typically utilize natural gas or distillate fuel oil.

Liquid fuels require their own pumps, flow control, nozzles and mixing systems. Many combustion turbines are available with either gas- or liquid-firing capability. In general, these combustion turbines can be converted from one fuel to another quickly. Several combustion turbines are equipped for dual fuel firing and can switch fuels with minimal or no interruption.

CHP Applications

An important advantage of CHP using combustion turbines is the high-quality waste heat available in the exhaust gas. The high-temperature exhaust gas is suitable for generating high-pressure steam, making combustion turbines a preferred CHP technology for many industrial processes. In simple cycle combustion turbines, hot exhaust gas can be used directly in a process or by adding a heat-recovery steam generator (HRSG) that uses the exhaust heat to generate steam or hot water to reach overall system efficiencies (electricity and useful thermal energy) of 70 to 80%.

Installed Costs

The basic gas turbine package consists of the gas turbine, gearbox, electric generator, inlet and exhaust ducting, inlet air filtration, lubrication and cooling systems, standard starting system, and exhaust silencing. The basic package cost does not include extra systems such as the fuel-gas compressor, heat recovery system, water-treatment system, or emissions-control systems such as selective catalytic reduction (SCR) or continuous emission monitoring systems (CEMS). Not all of these systems are required at every site. The total plant cost below consists of total equipment cost plus installation labor and materials (including site work), engineering, project management (including licensing, insurance, commissioning, and startup), and financial carrying costs during the 6-18 month construction period.

The cost estimates presented in this section are based on systems that include dry low emissions (DLE) control, unfired heat recovery steam generators (HRSG), fuel gas compression, water treatment for the boiler feed water, and basic utility interconnection for parallel power generation. There is no SCR system, no supplementary firing or duct burners, no building construction, no additional fuel handling, and minimal site preparation and support in the cost assessment. An SCR installation may add $80-$100/kW to the installed cost and increase variable cost by $2.0-$2.5/MWh, which will change depending on the cost of urea. To take into account the costs associated with building construction, fuel handling of distillate fuel oil, permitting, and site preparation, we recommend a 15% adder to the costs shown here.

Maintenance

Non-fuel operation and maintenance (O&M) costs are based on gas turbine manufacturer estimates for service contracts, which include routine inspections and scheduled overhauls of the turbine generator set. Routine maintenance practices include online running maintenance and preventive maintenance procedures. The fixed O&M costs include operating labor and total maintenance costs for routine inspections and procedures and major overhauls. Daily maintenance by site personnel includes visual inspection of filters and general site conditions. Routine inspections are required every 4,000 hours to ensure that the turbine is free of excessive vibration due to worn bearings, rotors or damaged blade tips. Combustion turbines need to be overhauled every 25,000 to 50,000 hours, depending on service, and the overhaul is typically a complete inspection and rebuild of components to restore the gas turbine to original or current (upgraded) performance standards

Table 8

Type	Sizes (kW)	Est'd Install Cost ($/kW)	Est'd Total Cost ($/kW)	CHP Cost ($/kW)	CHP Output (mmbtu /hr)	Full Load Heat Rate (btu/ kWh)	Effcy	Var O&M ($/ MWh)	Fixed O&M ($/kW-year)
Frame	1	1,700	1,960	320	7	15,600	22%	5	45
	5	1,000	1,150	125	26	12,600	27%	5	10
	10	1,000	1,150	85	47	11,800	29%	5	8
Aero-derivatives	0.5	2,000	2,300	600	4.4	16,100	21%	10	75
	3.0	1,150	1,320	185	7.4	13,000	26%	10	30

(heat rate and efficiency for HHV)

All costs in $2006

Manufacturers

Alstom
Nuovo Pignone
Solar Turbines
Rolls Royce - Allison
General Electric
Siemens
MTU - Vericor Power Systems

Microturbines

Microturbines are Brayton cycle engines and typically consist of a compressor, combustor, turbine, and generator. They range in size from between 25 kw and 350 kw, while conventional gas turbines can be as large as 250 MW.

Microturbines have several key advantages in comparison to other small scale power generators including a small number of moving parts, compact size, light weight, and low emissions. They are also suitable for both power-only and CHP applications. Microturbines operate at super-high speeds, with turbo-compressor speeds in excess of 80,000 rpm.

Types of Microturbines

There are generally two types of microtubines: recuperated and non-recuperated. With recuperation, electrical efficiencies are typically between 26-32% versus 15-22% for non-recuperated units.[17] Generally, electrical efficiencies increase as units become larger in size.

Fuel Options

Microturbines are designed to use natural gas as their primary fuel, but are able to operate on a variety of other fuels, including sour gases[18] (high sulfur, low btu content), biogas (LFG, digester gas), and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate.[19]

CHP Applications

In CHP operation, a second heat exchanger, the exhaust gas heat exchanger, transfers the remaining energy from the microturbine exhaust to a hot water system. Exhaust heat can be used for a number of different applications, including water heating, absorption cooling, space heating, and process heating. In CHP applications with microturbines, total efficiency can range from 65-80%. The costs of CHP applications with microturbines are discussed below.

Power generation using fuel cells combined with microturbines are also being developed by several manufacturers. These systems run the hot gas produced by fuel cells through a microturbine to generate additional electricity. Such hybrid systems can have particularly high efficiencies (60%).[20]

Microturbines in LFG Applications

Microturbines may have a particular advantage to other technologies in LFG applications for a number of reasons. Because individual microturbine units come in relatively small sizes, they can be used in landfills where the gas output in a particular area is too low for larger engines. In addition, microturbines may be advantageous in LFG applications because they are better able to combust lower methane content LFG than other technologies. In situations where air emissions are of particular concern, microturbines may be considered as they offer lower emissions than other technologies. If hot water could be utilized nearby, they offer the additional advantage of being able to offer a CHP application.

However, there are some drawbacks. Microturbines have a lower efficiency than reciprocating engines, particularly when running at part load.

Capital Costs

Some representative costs for power-only microturbine applications are shown below. These are budgetary estimates only. Installed costs will vary depending on the geographical area, current market

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[17] Recuperators are heat exchangers that use a microturbine's hot exhaust gases to preheat the combustor inlet air after it has been compressed.

[18] Unprocessed natural gas as it comes directly from the gas well

[19] With the emergence of biodiesel, it may be possible to operate a microturbine on biodiesel. However, given that there is little data currently available to suggest that this is a viable option, use of biodiesel for this purpose is not considered in this report.

[20] *Distributed Generation: Technologies, Opportunities, and Participants*, Research Reports International, October 2005.

conditions, special site requirements, emissions control equipment, and labor rates. Capital costs shown include equipment costs, labor and materials, project management, construction and engineering, and interest during construction; these costs also assume that the microturbines will operate on natural gas. These costs do NOT include site preparation, costs associated with fuel handling, or other additional costs associated with other fuel use (e.g., potential pre-treatment costs). In order to estimate total project costs, we suggest including a 25% adder to the costs shown below, to account for these other potential costs.

Table 9

Sizes (kW)	Est'd Install Cost ($/kW)	Est'd Total Cost ($/kW)	CHP Cost ($/kW)	CHP Output (mmbtu /hr)	Full Load Heat Rate (btu/ kWh)	Effcy	Var O&M ($/ MWh)
30	2,200	2,750	620	0.2	14,600	23%	25-30
70	1,940	2,420	340	0.4	13,500	25%	25-30
100	1,480	1,850	270	0.6	12,600	27%	15-30
350	1,320	1,650	180	2.0	11,800	29%	20

(heat rate and efficiency for HHV)

All costs in $2006

Maintenance

Microturbines are a relatively new technology, so there is not a large record of information regarding their availability and unit life. The design lives for microturbines are estimated to be anywhere in the 40,000 – 80,000 hour range. Manufacturers claim generally high availability (above 95%). Some data suggests microturbines should be able to run 3,000 to 4,000 hours between scheduled outages in peak shaving mode, and 8,000 hours in baseload mode.

Estimates for maintenance costs are between 0.6 to 1.8 cents per kWh. Manufacturers offer service contracts for maintenance priced at approximately 1.1 cents per kWh.[21] A gas microturbine overhaul is needed every 20,000 to 40,000 hours depending on manufacturer, design, and service. A microturbine operating on liquid fuels may require more frequent inspections and maintenance. The variable O&M costs shown in the table above include regular maintenance as well as estimates for overhaul costs. Non-fuel operations and maintenance costs when using microturbines in an LFG application are considerably higher than in natural gas applications, as much as 1.7 to 2.2 cents per kwh.[22]

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[21] Technology Characterizations: Microturbines, Energy Nexus Group, March 2002. The contracts include periodic inspections of the combustor and associated hot section parts and oil bearings in addition to the air and oil filter replacements.

[22] *Powering Microturbines with Landfill Gas*, EPA, October 2002.

Manufacturers

Bowman Power
Capstone Turbine Technology
Ingersoll-Rand Energy Systems
Turbec AB
Turbo Genset

Biomass

Direct-fired biomass combustion technologies

Most of the biomass[23] plants currently in commercial operation use a boiler/steam turbine technology for power production. These direct-fired combustion biomass technologies involve the oxidation of biomass with excess air, producing hot flue gases which produce steam in the heat exchange section of boilers. The steam is used to produce electricity in a steam turbine, using a Rankine cycle. Plant efficiencies for power-only applications average about 20% .

The capacity of biomass facilities is usually less than 50 MW, due to the dispersed nature of biomass feedstock and the large quantities of fuel required by larger plants; typically, plant size is 15 MW or greater due to economies of scale issues. However, facilities in the 5-15 MW range are feasible, and there are some existing projects in that size range. While there are a handful of companies in the region developing new technologies for relatively small-scale applications, the economics of projects less than 5 MW currently make this impractical compared to conventional DG. Such facilities have only been developed as demonstration projects to date.

Biomass facilities will usually have lower efficiencies compared to modern coal plants that use similar technologies, due to the lower heating value and higher moisture content of biomass fuel compared to coal. Generally, biomass facilities are expected to have a 20-25 year life.

Types of Technologies

The two common boiler designs used for steam generation with biomass are the stoker boiler and the fluidized bed boiler[24]. For stoker boiler technology, the biomass fuel is spread uniformly over the stoker grate surface. The boiler temperature serves to combust the finer biomass fuel particles in mid-air before they reach the stoker grate. The heavier particles reach the stoker grate and are burned as the grate travels from one end of the boiler to another. In a fluidized bed boiler, the biomass is injected into the bottom of a hot sand bed below the furnace. A stream of upward flowing air suspends (or fluidizes) the bed. This raises the sand bed through the biomass material, which combusts the biomass. This energy is turned into steam and then is transferred to a steam turbine.

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[23] In this section, biomass refers primarily to wood and woody waste.

[24] Note there are other technologies for utilizing biomass for electricity generation, which includes gasification of biomass prior to combustion. However, biomass gasification technologies have not been considered in this report, as they are not commercially available on a wide-scale at this time. Currently, there are a few demonstration projects in the U.S. and commercialization is expected over the next 5-10 years. The cost characteristics of a gasification project will largely depend on how quickly the technology is commercialized, but are presently more costly than fluidized bed technology.

Although a fluidized bed boiler tends to have higher capital costs than a stoker boiler, the fluidized bed boiler technology is more fuel efficient than the stoker boiler technology. It is also capable of burning a variety of biomass residues with various moisture content and particle sizes, while producing lower emissions due to lower temperatures used during combustion and more complete combustion of particles allowed by the bed. For this reason, we assume that most new greenfield biomass projects will primarily use fluidized bed applications[25]; this is consistent with recent biomass project proposals in the region.

CHP Applications

Direct-fired biomass facilities may also be used in combined heat and power (CHP) applications, presuming the proximity of a sufficient thermal load. CHP using biomass has existed for decades, predominantly in the pulp and paper industry, which uses its waste wood for fuel, and the resulting process steam to dry the incoming green wood. Efficiencies with a CHP application can reach 60%, greatly improving project economics.

Fuel Options

Types of biomass fuel, often in the form of wood chips, that are commonly used in both stoker and fluidized bed boilers include:

- Forest thinnings – This includes underbrush and saplings and fallen or dead trees.
- Forest residues – These are residues resulting from active forest management and commercial logging operations.
- Primary mill residues – Operations such as sawmills, paper and pulp companies, and other millwork companies produce primary residues in the form of bark, chips, sander dust, edgings, and sawdust.
- Yard trimmings – Woody yard trimmings are an abundant source of wood sent to landfills. In addition, this waste can also be generated from right of way trimmings near railroads and utility lines.
- Whole tree chips.

While both types of boilers can utilize similar biomass fuels, fluidized bed boilers are generally more flexible in the types of fuel they can fire, and in fact can often fire fuels with different characteristics (including moisture content and particle size) simultaneously. Construction and demolition (C&D) waste is woody waste material that is being considered as a low-cost fuel option. Because this type of biomass is less homogenous in its consistency than other types of biomass, the fluidized bed boiler is more adapted to utilize this type of fuel. Several new proposed fluidized bed boilers in the region intend to use C&D for a portion of their feedstock.

Capital Costs

For applications in the 20 MW size range and higher, total project costs are likely to be within the $2,500-$3,000/kw range, depending on exact size, location, and development costs. Costs for applications less than 20 MW are likely to be considerably higher: approximately $3,500/kw for applications in the 10-15

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[25] We note that another alternative is to install a stoker boiler with emissions control technologies. Our research has shown that the cost of a stoker boiler with a regenerative SCR is approximately equivalent to the cost of a fluidized bed boiler application.

MW range, and up to $15,000/kw for considerably smaller applications (approximately 1 MW). Significant O&M costs and reduced efficiencies would also make such small facilities impractical.

The costs shown in the table below include equipment costs, construction and commissioning services, as well as costs associated with building and installing the biomass fuel receiving, processing, storage and metering equipment. However, they do not include costs associated with site-specific work (e.g., clearing), permitting studies, and connection to the electric grid. For these costs not included, we suggest adding a 15 % adder to the costs shown in the table below.[26]

Maintenance Costs

Operations and maintenance (O&M) costs are categorized as fixed and variable. Variable O&M costs, which include the cost of non-fuel consumables such as chemicals, water, and electricity needed to run the equipment, are generally estimated to be between $5-$10/MWh. Fixed O&M includes both labor costs – i.e., the cost of employees needed to operate and maintain the plant – as well as non-labor costs such as spare parts and maintenance equipment, generally estimated to be 2% of the capital costs of the plant. Total fixed O&M costs can range from $100-150/kw-yr for the larger facilities (20 MW and up) to $200-300/kw-yr for smaller facilities (10-15 MW).

Table 10

Type	Sizes (MW)	Est'd Install Cost ($/kW)	Est'd Total Cost ($/kW)	Full Load Heat Rate (btu/ kWh)	Effcy	Var O&M ($/ MWh)	Fixed O&M ($/kW-year)
Stoker Boiler	0.7	10,500	12,070	20,000+	17%	10+	1,800
	10	2,800	3,220	18,000	19%	5-10	180
	15	2,400	2,760	18,000	19%	5-10	130
	25	2,000	2,300	15,000	23%	5-10	100
Fluidized Bed	0.7	18,000	20,700	20,000+	17%	10+	2,200
	10	3,500	4,030	17,000	20%	5-10	220
	15	3,100	3,570	17,000	20%	5-10	170
	25	2,500	2,880	14,000	24%	5-10	125

As the chart above shows, fixed costs for these biomass technologies are relatively high in comparison to the other distributed generation technologies considered. However, biomass fuel costs are considerably lower than fossil fuel costs. In addition, a federal production tax credit (PTC) for biomass energy provides a facility with an approximate $9/MWh tax credit for the facility's output.[27] Thus, as illustrated by Figure 4 in the Indicative Total Cost section of this report, depending on the capacity factor required of

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[26] We have not been able to find comparable estimates for CHP capital costs (i.e., costs for similar biomass technologies at similar sizes). At smaller sizes - for instance, a 6 MW facility - biomass steam boiler systems with CHP can cost as much as $7,000/kw. However, for larger sizes, we would expect significant economies of scale.

[27] The PTC currently applies to all biomass facilities that are on-line by December 31, 2007. The $9 credit is escalated by inflation annually, and applies to open-loop biomass sources only . A greater tax credit ($18/MWh) applies to closed-loop biomass sources. However, our estimates show that because closed-loop biomass fuel resources will likely be much more expensive, the greater tax credit does not currently provide an incentive to developed closed-loop resources vis-à-vis open loop resources.

the DG resources, biomass may or may not be cost-effective vis-à-vis other resources. In addition, biomass facilities may be eligible for Renewable Energy Credit (REC) revenues, if they qualify for the CT, MA, or RI Renewable Portfolio Standards. We assume a modest \$10/MWh REC revenue, as shown in the Indicative Total Cost section. This REC value is based upon our conservative view of long-term REC prices and our work on other projects, although the number can range between \$3-\$53/MWh. This revenue would reduce the net cost of a project only if the RECs can be sold out-of-state.

Manufacturers

Energy Products of Idaho
Kvaerner Power
Babcock & Wilcox
Foster-Wheeler

Fuel Cells

Fuel cells are electrochemical devices that convert chemical energy in fuels into electrical energy directly, promising power generation with high efficiency and low environmental impact. Because the intermediate steps of producing heat and mechanical work typical of most conventional power generation methods are avoided, fuel cells are not limited by thermodynamic limitations of heat engines such as the Carnot efficiency. In addition, because combustion is avoided, fuel cells produce power with minimal pollutants. Since there are no moving parts, maintenance costs are reduced. It is a quiet operating system. Furthermore, fuel cells, due to their modular nature, have excellent load following capabilities once operating, but do require long start-up and shut-down times.

Though fuel cells could, in principle, process a wide variety of fuels and oxidants, of most interest today are those fuel cells that use common hydrocarbon fuels (or their derivatives) or hydrogen. Hydrogen itself is not a practical fuel source currently because of a lack of distribution infrastructure. Lower temperature fuel cells are more likely to become contaminated by impurities, such as CO and sulfur. On the other hand, high-temperature fuel cells are better at processing conventional hydrocarbon gaseous fuels and, thus, are better options for DG applications. Due to the high installed cost of fuel cell systems (3-5 times that of conventional technologies), the most prevalent DG applications involve CHP applications, which coincide with fuel cells that operate at higher temperatures. Thus, fuel cells operating as CHP are likely to be baseload units with some load-following capability.

In addition to having high installed costs relative to other DG systems, fuel cells for commercial operations are still fairly new in the market: thus, endurance and reliability have not yet been fully demonstrated either.

Most fuel cell power systems comprise a number of components:

- **Unit cells**, in which the electrochemical reactions take place
- **Stacks**, in which individual cells are modularly combined by electrically connecting the cells to form units with the desired output capacity
- **Balance of plant** which comprises components that provide feedstream conditioning (including a fuel processor if needed), thermal management, and electric power conditioning among other ancillary and interface functions

Types of Fuel Cells

A variety of fuel cells are in different stages of development, most still in pre-commercial stages. The most common classification of fuel cells is by the type of electrolyte used in the cells: 1) polymer electrolyte fuel cell (PEFC); 2) alkaline fuel cell (AFC); 3) phosphoric acid fuel cell (PAFC); 4) molten carbonate fuel cell (MCFC); and 5) solid oxide fuel cell (SOFC). The only technology that has had some commercial deployment is PAFC, but the company has stopped production of the technology to focus on PEFC technology instead.

Broadly, the choice of electrolyte dictates the operating temperature range of the fuel cell. The operating temperature and useful life of a fuel cell dictate the physicochemical and thermo-mechanical properties of materials used in the cell components (i.e., electrodes, electrolyte, interconnect, current collector, etc.). Aqueous electrolytes are limited to temperatures of about 200 °C or lower because of their high vapor pressure and rapid degradation at higher temperatures. MCFC and SOFC operate at temperatures greater than 600 °C.

The table below provides an overview of the key characteristics of the main fuel cell types.

Table 11

Characteristic	PEFC	AFC	PAFC	MCFC	SOFC
Electrolyte	Polymeric ion exchange membranes	Potassium hydroxide	Phosphoric acid	Molten carbonate	Perovskites (ceramics)
Catalyst	Platinum	Platinum	Platinum	Nickel/Nickel oxide	Perovskites
Operating Temperature	40-80 C	65-220 C	205 C	650 C	600-1000 C
External Reformer	Yes	Yes	Yes	No, for certain fuels	No, for certain fuels
Primary Contaminate Sensitivities	CO, Sulfur, and NH3	CO, CO2, and Sulfur	CO<1%, Sulfur	Sulfur	Sulfur
CHP Application	No	No	Yes	Yes	Yes

Fuel Options

The operating temperature also plays an important role in dictating the degree of fuel processing required. In low-temperature fuel cells, all the fuel must be converted to hydrogen prior to entering the fuel cell using a fuel reformer. In addition, the anode catalyst in low temperature fuel cells (mainly platinum) is strongly poisoned by CO.

In high-temperature fuel cells, CO and even CH4 can be internally converted to hydrogen or even directly oxidized electrochemically. High-temperature fuel cells are better at processing most hydrocarbon fuels (LPG, sour gas, LFG, biogas) without a fuel reformer. Therefore, MCFC and SOFC are attractive technologies that do not need a fuel reformer and, due to the high-temperature operations, can provide heat recovery for CHP applications. However, the drawback of both technologies is that they are still in pre-commercial/demonstration phases.

CHP Option

For the higher temperature fuel cells, hot water recovery is the simplest thermal load to supply. Primary applications for CHP in the commercial/institutional sectors are those building types with relatively high and coincident electric and hot water/space heating demand. Prices in the table below include CHP equipment.

Footprint/Land Requirement

A fuel cell is normally comprised of multiple units/stacks combined in a modular fashion. A 250 kW project typically has a footprint of about 500 square feet. Due to the modular nature of fuel cell systems, the footprint increases proportionally with size.

Installed Costs

Current estimated installed costs for the two technologies (MCFC and SOFC) that are practical for DG applications are high because the costs are based on pre-commercial demonstration projects of greater than $5,500/kW. Actual costs will vary widely depending on site requirements. These technologies have not achieved levels of mass production that can bring the cost down to more competitive levels. Additionally, beyond the stack system, many of the ancillary and power/fuel/thermal management systems are still in development phases. The goal of the industry is to bring costs down well below $2000/kW, but the goal will likely not be achieved in the near-term. A 10% cost adder to cover soft costs was assumed for this technology.

Maintenance

Maintenance costs for fuel cells vary with the type of fuel cell, size, and maturity of the equipment. Some of the typical costs include maintenance labor, ancillary replacement parts, and major overhauls usually after five years.

Table 12

Type	Sizes (kW)	Est'd Install Cost ($/kW)	Est'd Total Cost ($/kW)	Heat Output (MMBtu /hr)	Elect Effcy	Fixed O&M ($/kW-year)
SOFC	0.25	5,000	5,500	0.48	45%	90
MCFC	0.25	5,000	5,500	0.44	43%	100
	2.0	3,500	3,850	3.56	46%	40

Manufacturers

Siemens Power Generation
UTC
Fuel Cell Technologies

IX. Indicative Total Cost Estimates

Based on cost estimates for each technology discussed in the sections above, we derived indicative total costs, using a real levelization methodology. Fuel cells were excluded because of their high capital and fixed O&M costs. Total costs were determined on a fixed ($/kw-yr) and variable ($/MWh) cost basis. The fixed costs include annualized initial project costs and any annual fixed maintenance costs that would occur, regardless of the how often the unit actually operated. The variable costs include both fuel costs and operations and maintenance costs that are dependant on the actual output of the unit. Note total costs for the unit would include both the fixed and variable components. We also provide an indicative total cost of energy, at various levels of operation (capacity factors – see figure 4). Providing costs on such a basis allows for a comparison of total costs at various levels of output. All costs are shown on a real-levelized basis, consistent with the methodology used in the CVPS economic model.

These costs were derived using the following key assumptions:

- Initial project costs (including capital costs, installation, and other development costs) were annualized using a carrying charge of 10% on capital costs. This factor is consistent with that used in the CVPS economic model for distribution generation technologies. This factor was derived assuming an approximate 25 year project life, a weighted average after-tax cost of capital of about 8% (consistent with the CVPS cost of capital), a 40% tax rate, and assumed inflation of 2.5% annually.
- Consistent with the real-levelized methodology, both fixed and variable operations and maintenance costs are based on $2006, and expected to escalate at the rate of inflation over time.
- Fuel costs are based on approximate levels, for illustrative purposes. Actual fuel costs may vary, and may escalate at a different rate than going forward inflation.
- Heat rates shown are approximate for new units. Over time, a unit may experience some heat rate degradation due to normal wear and tear from operations. This is not captured in the fuel cost estimates shown.
- As discussed in the biomass section of this report, we assume the potential biomass facilities would qualify for the Production Tax Credits (PTC) of $9/MWh, and the facility would receive modest Renewable Energy Certificate (REC) revenues of $10/MWh. Such revenues make biomass facilities relatively economic at capacity factors above 40%, as shown in Table 13 and in the graph in Figure 4 below.

This analysis of Indicative Total Costs is for summary information only, and should not replace a more thorough analysis of the economic impact of DG options that will be conducted by CVPS.

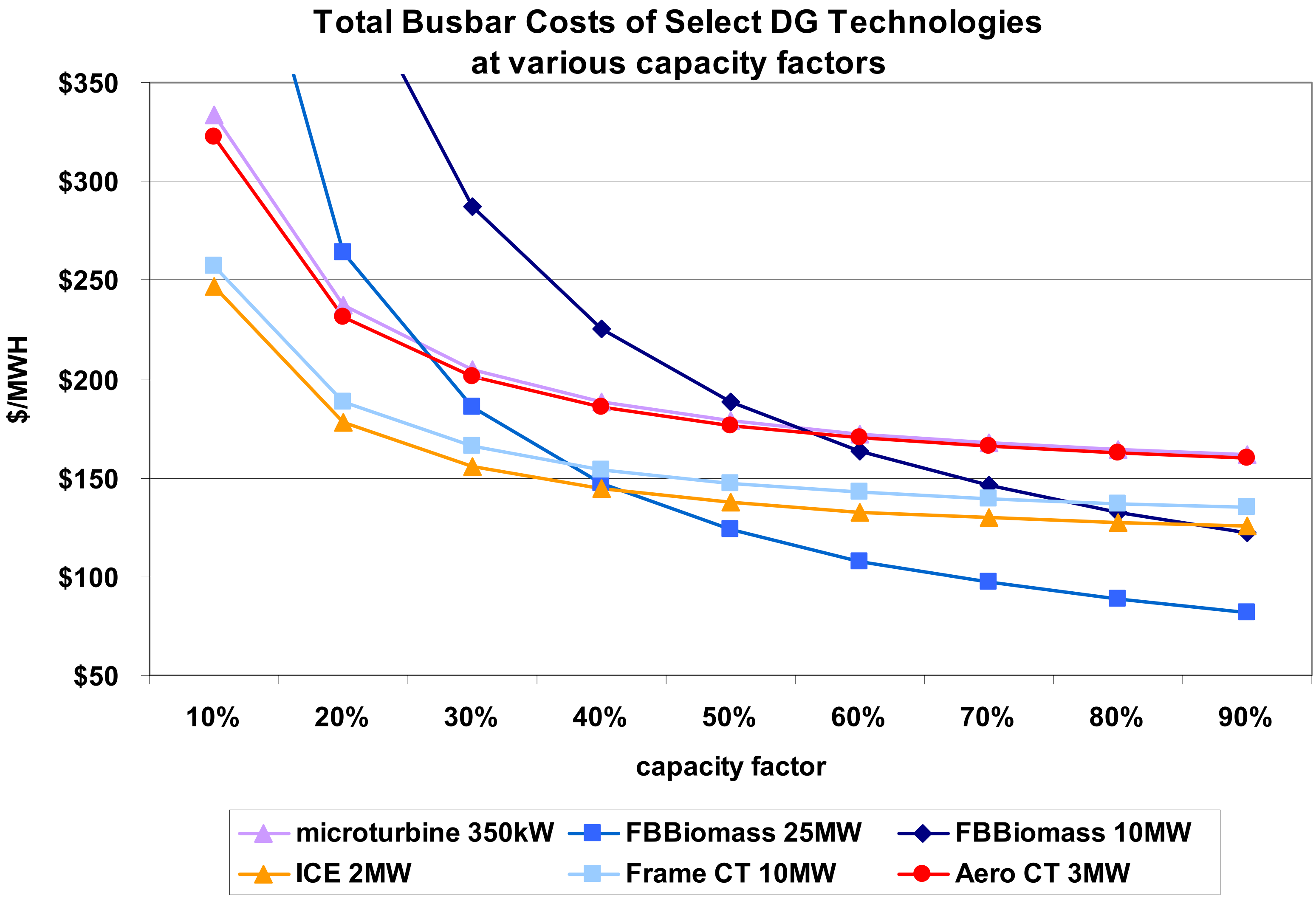
Table 13

Assumptions for Indicative Cost Comparison of Sample Technologies

Technology	Microturbines	Fluidized Bed (Biomass)		ICE[1]	Frame CT	Aeroderivative CT
Size (MW)	350 kW	25 MW	10 MW	2 MW	10 MW	3 MW
Capital Cost, $/kw	1320	2500	3500	1100	1000	1150
Project Soft Costs and Contingency %	25%	15%	15%	10%	15%	15%
Total Project Costs, $/kw	1650	2880	4030	1210	1150	1320
Fixed O&M, $/kw-yr		125	250	2	8	30
All-In Fixed Cost (no operation), $/kw-yr	**170**	**410**	**650**	**120**	**120**	**160**
Fuel Cost, $/MWh	118	42	51	95	118	130
Fuel Cost, $/mmbtu	10	3	3	10	10	10
Heat Rate, btu/kwh	11,800	14,000	17,000	9,500	11,800	13,000
Variable O&M, $/MWh	20	7	10	13	5	10
Production Tax Credit ($/MWh)		9	9			
Renewable Energy Credit ($/MWh)		10	10			
Total Variable Cost, $/MWh	**140**	**30**	**40**	**110**	**120**	**140**

[1] Costs represent 2 MW diesel engine.
Fuel assumed is for distillate fuel oil.

Figure 4


Total Busbar Costs of Select DG Technologies
at various capacity factors
$/MWH
$350
$300
$250
$200
$150
$100
$50
10%
20%
30%
40%
50%
60%
70%
80%
90%
capacity factor
microturbine 350kW
FBBiomass 25MW
FBBiomass 10MW
ICE 2MW
Frame CT 10MW
Aero CT 3MW