Virtual Batteries

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Preface

The author of this non-proprietary white paper has been active in fuel cell development since 1985 and is presently Vice President – Technology of Technology Management, Inc. (TMI) in Cleveland, Ohio. TMI is exclusively dedicated to commercializing its proprietary solid-oxide fuel cell systems. Robert has BSE degrees in Chemical and Metallurgical Engineering from the University of Michigan and a PhD in Materials Engineering from MIT. Prior to joining TMI in 1993, he held technical management positions with British Petroleum (BP), Standard Oil (Sohio), and Chase Brass and Copper.

The concepts summarized herein are expansions of the fuel cell system concepts under ongoing development at TMI. While all of the systems described below incorporate TMI fuel cell technology, many other highly attractive TMI fuel-cell systems would perform no virtual battery functions.

For consistency in this paper, all financial figures are in nominal (inflated) dollars and prices are quoted per kilowatt-hour (multiply by 1000 for prices per megawatt-hour). Section 8.2 contains a list of abbreviations.

1. Summary

Virtual batteries are defined herein as stationary grid-connected systems which can operate as if they were storing electricity for later delivery, but do not actually perform storage. Unlike ordinary rechargeable batteries, *their output energy is independent of input energy with respect to both quantity and timing*. Virtual batteries can enhance solar and wind generation. They can accept surplus grid power at any time and deliver extra power to the grid at desired times (even different seasons).

The virtual battery systems described herein promise excellent returns on investment, unlike conventional battery systems (whose storage costs are typically over four times higher). They would reduce costs for grid-power users, increase utility profits, and provide uninterruptible power. The proposed systems could also replace net U.S. petroleum-related imports with exports and reduce fossil CO_2 emissions by 25%.

Four types of stationary systems with virtual-battery capabilities are proposed: natural gas fuel cell, propane fuel cell/cogeneration, natural gas to ammonia, and biomass to biogasoline. Grid power would be purchased when prices are low and fuel-cell power sold to the grid when prices are high. At intermediate grid prices, grid power to/from the virtual batteries would be zero (except for the propane system in cool or cold weather).

2. Problem and Opportunity

2.1 Electricity Generation

Electric power plays an essential and growing role in the United States. Table 1 shows actual and forecast totals from the Energy Information Administration (EIA) of the U.S. Department of Energy (Reference 1).

Table 1. U.S. Electricity Generation and Consumption

	Billion kWh			Share	
	2015	2040	APR	2015	2040
Natural Gas	1348	1942	1.47%	33.3%	38.7%
Coal	1355	919	-1.54%	33.5%	18.3%
Nuclear	798	789	-0.05%	19.7%	15.7%
Solar	38	477	10.70%	0.9%	9.5%
Wind	190	473	3.72%	4.7%	9.4%
Hydroelectric	247	298	0.75%	6.1%	5.9%
Other Renewables	72	127	2.27%	1.8%	2.5%
Generation	4047	5024	0.87%	100.0%	100.0%
Consumption	3873	4805	0.87%		

Extrapolation predicts 2050 generation to be 5700 billion kWh, with consumption 5450 billion kWh. The DOE forecasts nearly 8% of the 2040 total will be obtained from distributed generation at user sites (much from solar). The Other Renewables category is mainly from biomass. Major increases from solar, wind, and natural gas (and a large decrease from coal) are predicted. Over 99% of power users are connected to the electric power grid.

The retail value of the Table 1 electricity was $400 billion in 2015 (average of $0.103/kWh) and is forecast to reach $845 billion ($0.176/kWh) in 2040 (using 2040 dollars). Extrapolation gives a projected value of $1170 billion ($0.215/kWh) in 2050. Grid power users always desire high reliability and minimum costs.

Electric utility companies deliver and bill power obtained from multiple generation sources (see section 2.4). The electric grid includes both transmission lines (which transport large quantities of power at high voltages) and distribution lines (which are connected to each customer). The transmission and distribution function is abbreviated "T&D". Most of the distributed sources are also users. Electricity pricing is discussed in section 2.7.

Energy-related U.S. fossil CO_2 emissions are forecast in Ref. 1 to slowly increase after 2030, reaching an extrapolated 2050 total of 5.17 billion (metric) tonnes per year, with about 31% from electric power generation and 34% from transportation.

2.2 Problem Statement

Since the dawn of the electricity grid over a hundred years ago, it has been necessary to ***continually balance*** power generation and use (supply and demand). Balancing is required since available methods for storing sizeable amounts of electricity are virtually non-existent (the minor exceptions are described in section 5.3). The use of large battery storage systems has been demonstrated, but such systems are far too expensive in nearly every case (see section 5.1). The balancing methods described below have been in successful use for decades. However, they are becoming increasingly costly (with costs ultimately borne by users). The recent and projected rapid growth in solar and wind capacity is making it more and more challenging to continually balance supply and demand. Section 2.3 summarizes factors which vary electricity demand, followed by section 2.4 describing supply variables. Utilities continuously act to vary or influence both supply and demand to maintain balance. Computer systems perform some actions directly and advise grid operators about other potential actions. Communications between utility companies employ multiple paths and various types of price negotiations.

2.3 Electricity Demand

Each electric utility operates a distribution grid which serves many users: a combination of residential, commercial, and industrial customers. Instantaneous power use depends upon multiple factors. Those not subject to influence or control by the utility include the following:

1. Time (hour of day, day of week, day of year, and holidays)
2. Weather (temperature, humidity, wind, and sunshine)
3. Partial Grid Outages (caused by weather or equipment breakdowns)

Three factors allow the utility to influence system power demand:

4. Time-of-Use (TOU) Pricing (discussed in section 2.7 below)
5. Voltage Adjustments (within allowable limits, usage varies slightly with voltage)
6. Rolling Blackouts (some users are disconnected temporarily)

Rolling blackouts are preferentially used on customers with (lower-price) interruptible contracts, who usually have backup generation systems.

Many commercial and industrial customers have a fairly uniform load profile (load versus time) and hence a high load factor (average load/peak demand). Most residential customers have a highly variable load profile and a very low load factor. Other commercial and industrial customers fall between the extremes. Aggregate system demand exhibits a clear seasonal pattern in most parts of the U.S. In the future, increased use of plug-in vehicles and electric heat pumps could alter load profiles and increase consumption.

2.4 Electricity Supply

Each distribution utility receives its supply from multiple sources: generation companies (some of which might be subsidiaries of the utility), other utilities, and distributed sources (mostly customers). Uncontrollable (or mostly uncontrollable) reasons for supply variations include:

1. Wind Speed (affecting wind turbines)
2. Solar Intensity (due to time of day, weather, and day of year)
3. Equipment Breakdowns (generation or transmission)
4. Droughts (affect cooling water supplies and hydro turbines)
5. Variations in Distributed Sources (from many reasons)

Controllable means of varying supply include:

6. Trimming of base-load generation units (mostly natural gas combined-cycle, coal, and nuclear)
7. Peaking gas-turbines start/stop and trimming
8. Purchases and sales to other utilities
9. Planned maintenance outages
10. Deliberate variations in hydroelectric water flow
11. Shutting down solar or wind equipment

Most base-load systems have limited trimming capability. The use of gas turbines is the major method of supplying extra power most of the time (discussed in section 2.5). Transfers to other utilities are often limited by their supply/demand situation and by unfavorable prices (some sales have negative prices while purchases can cost up to over $1.00/kWh). Planned maintenance projects may last for minutes to months, but are of limited use for balancing. Few utilities have significant hydroelectric sources. Solar inverters can be turned off and wind turbines furled (but utilities will still pay outside sources for their lost energy).

When a smaller total supply is needed, marginal variable cost of electricity (to the utility) can approach zero since base-load systems will continue to generate significant power and the utility must accept and pay for most distributed power. Disposing of excess power to other utilities (even at negative prices: paying them to accept) is often necessary.

Electricity users with on-site solar or wind generation usually use the utility grid as a virtual battery: they export excess power to the grid and import grid power at other times. This type of virtual battery is excluded from further discussion in this report (the continued and growing use of user-owned renewables is assumed, which increases the problem to be solved).

2.5 Peaking Gas Turbines

Peaking turbine-generators in the U.S. virtually all use natural gas fuel and are simple-cycle systems. Although units are sold with capacities from under 1 to 370 MW, most individual peaking units are 10 to 100 MW. Typical lower heating value (LHV) efficiencies are slightly over 30% (increasing with system size and decreasing with ambient temperature).

Using 2025 forecast electric-utility natural gas cost from Ref. 1 (shown in Table 3), a Solar Turbines model Mars 100 was used for a marginal peaking generation cost estimate. Its net capacity (delivered to user) is about 10.8 MW and its installed cost about $8.9 million. If the unit operated an average of 4 hours per day (the duty assumed in many later calculations in this paper), total generation cost in 2025 was calculated to be $0.143/kWh. Average delivered costs of peaking power to users (after adding T&D and utility fixed overhead) is $0.223/kWh (residential), $0.199/kWh (commercial), and $0.163/kWh (industrial). These figures include no profit. The cited costs are well above utility mean costs from all sources, because of the low capacity factor (4/24 hours = 17%) and the moderate fuel efficiency of peaking units. Delivered power from natural gas peaking turbines has CO_2 emissions averaging about 600 g/kWh (higher than the predicted 2025 grid average of 450 g/kWh).

Peaking turbines larger than the above example will have lower installed cost per MW and somewhat lower delivered power costs. However, the above example is considered representative of marginal cost, since small units can fine-tune the supply/demand balance.

“Black starts” (cold startups) of peaking turbines require up to 30 minutes (longer for larger units). They can be hot idled (called “spinning reserve”) to deliver power within seconds. However, hot idling increases fuel and maintenance costs per kWh delivered. Since peaking turbines have limited turndown (trimming) capability, utilities typically have numerous units (often of more than one size) for superior flexibility.

When other utilities offer high prices for power purchases, peaking power is profitably sold to them. Utilities require sufficient reserve peaking capacity to handle worst-case system demands (which often occur in very hot weather), even with occasional major equipment outages.

2.6 Backup and Uninterruptible Power

Users may experience grid power outages lasting from under one second to many days. Average availability of grid power in the U.S. approaches 99.9% (“three nines”), but 0.1% is 9 hours per year. Many users have lower availability. Tree growth and equipment aging are leading to declining grid reliability in many communities. Worsening storms are another cause of outages. Even very brief grid outages be inconvenient, causing loss of computer data, require rebooting of devices, and necessitate resetting clocks.

An increasing number of users have installed backup generators (also called standby or emergency generators), which are sized to power the entire site or a part of it. Permanently installed generators use natural gas fuel when available, or else propane or diesel. They usually have automatic startup and switching and can provide backup power to the site in under one minute. Backup generators are available in sizes from about 5 kW upwards. Their installed cost ranges from under $400 to over $1000 per kW. Run times for natural gas units is unlimited, while propane or diesel units can typically run for several days before their tanks must be refilled.

Uninterruptible power supplies ("UPS") using batteries, an inverter, and automatic switching are also available. They will provide continuous power to connected loads when a grid outage (or serious disturbance) occurs. Available power capacities range from about 0.1 kW to many kW, with backup times from minutes to many hours (or even multiple days). Typical UPS systems cost roughly $1000 per kWh, but considerable variations exist. Some such systems are integrated with backup generators and/or solar photovoltaic arrays (which can therefore provide backup power for extended to unlimited times). Cellular-telephone systems in the U.S. have multi-kW UPS systems with backup generators and large battery banks (with high annual replacement costs even when not utilized).

Section 5.1 discusses battery systems and their costs.

Portable gasoline generators are another possible source of backup power. Although they cost less per kW, they are much less convenient, often quite dangerous, and considerably slower to supply replacement power.

2.7 Prices
Reference 1 forecasts average U.S. retail electricity prices (in inflated dollars) for residential, commercial, and industrial users in 2025 and other years. These prices (converted to kWh) are listed in the Middle column of Grid Sell in Table 2. By 2025, it is expected that many if not most power customers will be charged time-of-use (TOU) prices, which reflect utility supply and demand. In Table 2, Low TOU prices are assumed to be 50% of the Middle, and High prices 150%. If the total annual kWh used at high and low prices were equal, the annual average would equal the Middle column (same as the DOE forecast).

The average prices shown for commercial and industrial customers is based upon annual power use rather than type of user: a sliding scale exists with larger users paying less per kWh.
In most states today, “net metering” is in effect, whereby users sell power at the same price they buy it. This is arguably unfair to the utilities and is being slowly replaced with lower Grid Buy prices. Table 2 lists example average grid buy prices which are lower (except for Industrial High, which is equal).

Table 2. Example 2025 Time-of-Use Prices

	per kWh		
	Low	**Middle**	**High**
Grid Sell to User			
Residential	**$0.081**	**$0.162**	**$0.243**
Commercial	**$0.067**	**$0.134**	**$0.201**
Industrial	**$0.045**	**$0.090**	**$0.135**
Average	**$0.066**	**$0.131**	**$0.197**
Grid Buy from User			
Residential	**$0.067**	**$0.135**	**$0.206**
Commercial	**$0.056**	**$0.111**	**$0.183**
Industrial	**$0.037**	**$0.075**	**$0.135**
Average	**$0.054**	**$0.109**	**$0.164**

Actual utility bills to users show many details which add up to the averages. Rates vary considerably in different parts of the country and by amount of usage. In the Table 2 example, the three columns are intended to be the averages if more than one price applies: e.g., the 50% low price might actually be half at 40% and half at 60%.

TOU pricing has two goals: to provide an incentive for users to alter power-usage timing and to reflect utility variable costs as their system load fluctuates. In the future, TOU pricing may vary both on a fixed time schedule (by month, day of week, and hour of day) and also in a dynamic manner in response to real-time supply and demand. Price signals could be continually sent to users via secure internet link, with perhaps one-hour minimum intervals between changes.

In the cost examples used in chapters 3 and 4, middle prices are assumed to average 12 hours per day, low prices 8 hours, and high prices 4 hours. Mean power use (kW) is assumed to be 100% of average at middle price, 75% at low price, and 150% at high price. The resulting energy (kWh) used at high price thus equals that used at low price in these examples. Individual users need not follow any particular pattern.

The High column in the Grid Buy from User section of Table 2 shows lower prices than the delivered cost of peaking power cited in section 2.5. The utilities therefore have at least two incentives to buy power from users instead of using additional peaking turbines: savings in variable costs and net CO_2 emission savings. Utility purchases of power from users will also lower stresses on the grid, reducing maintenance costs.

2.8 Opportunity Statement

A major opportunity exists for grid-connected virtual battery systems having the attributes listed below. This opportunity is expected to grow significantly as more wind and solar generation is added. Indeed, the extensive deployment of cost-effective virtual battery systems is expected to facilitate additional growth in wind and solar capacity.

A virtual battery system is defined as one which can operate as if it stored electrical energy for later delivery without actually storing energy (unlike rechargeable batteries, which convert electricity to and from chemical energy).

The desired attributes of a virtual battery system include the following:

1. **Cost Advantages** versus alternatives for load balancing
2. **Attractive Return on Investment** to system owner
3. **Uninterruptible Power** to entire site throughout grid outages
4. **Capacity Flexibility**: output energy independent of input energy (larger or smaller)
5. **Timing Flexibility**: output independent of input (differing by months if desired)
6. **Rapid Response**: mode switching (input/zero/output) within minutes
7. **Environmental Advantages** over alternatives

Cost advantages should lead to both lower user rates and enhanced utility profits.

If virtual-battery output were 10% of projected 2050 U.S. electricity use (section 2.1), total output energy capacity would be 570 billion kWh per year. If average virtual-battery output time were 4 hours per day, output power would average 390 GW (about one-fourth of expected 2050 total generation nameplate capacity). Virtual-battery total annual input energy might be close to its output.

Section 6.2 provides estimates of projected financial benefits to power users and system owners, together with investment requirements and environmental advantages.

Chapters 3 and 4 describe two categories of proposed virtual battery systems. The numerical examples have output electrical energy (MWh/yr) at high grid price equal to input at low grid price. However, all these systems have capacity flexibility (attribute 4 above) and timing flexibility (attribute 5 above).

3. Fuel Cell Systems

Fuel cell systems have been under development in multiple countries for many decades. Many have demonstrated good electrical and high energy (electrical plus thermal) efficiencies, reliability, safety, low noise, and fuel flexibility. Installed and maintenance costs have declined and are expected to further decline significantly in the future. Their electrical output capacities range from under one kilowatt to multi-megawatt. They can be integrated with the utility grid and with optional solar PV arrays. Expected future models will be suitable for residential, commercial, and industrial installations.

Their preferred fuel for stationary installations is natural gas, with propane being a higher-cost alternative. Forecast efficiencies and installed costs for TMI solid oxide fuel cell systems are used in this chapter. Net AC output/fuel LHV efficiencies are assumed to be 45%. The maximum energy efficiency (electrical plus thermal) of propane cogeneration systems is assumed to be 108% LHV (99% HHV) in cold weather.

Ref. 1 forecasts the Table 3 average fuel prices in 2025 in the U.S. (energy units have been converted to lower heating value). The Electric Power price is that paid by utilities. The Table 3 prices will vary locally in the U.S. (they include both fixed and variable charges).

Table 3. 2025 Average Fuel Prices

Category	per kWh LHV	
	Natural Gas	Propane
Residential	**$0.054**	**$0.097**
Commercial	**$0.047**	**$0.086**
Industrial	**$0.028**	**$0.076**
Electric Power	**$0.025**	
All Users	**$0.034**	**$0.087**

The proposed fuel cell systems discussed in this chapter would be installed at user sites, connected to both site electric loads and the utility grid, and configured to act as whole-site UPS systems for unlimited times during grid outages. They would disconnect from the grid within milliseconds of a grid outage or major disturbance, automatically reconnecting when stable grid operation resumed.

When grid sell-to-user prices are lower than variable costs, the fuel cell system would be hot-idled and site electrical loads powered from the grid. When grid buy-from-user prices are higher than marginal variable costs, the fuel cell system would generate maximum power and export (sell) the excess to the grid. At intermediate prices, the fuel cell system would usually power site loads only (“load follow”), with no import or export. However, propane cogeneration systems would also operate at maximum power when outdoor temperatures are low (section 3.2). The combination of site loads and fuel cell system would thus act to the grid as a virtual battery.

The generation capacity (expressed in kW) of the fuel cell system will usually be selected to at least handle the maximum sustained demand of the site (which can be considerably larger than the annual average use). An integrated battery system will supply peak-power needs during grid outages. The ratio of installed fuel cell capacity to average site load will typically be highest for residential systems and lowest for industrial systems.

The low cost of natural gas (Table 3) versus grid electricity (Table 2) allows natural gas fuel cell virtual-battery systems without heat recovery to be profitable (section 3.1). The higher cost of propane fuel requires the addition of cogeneration to achieve profitable virtual-battery operation (section 3.2).

It is expected that both types of fuel cell systems described in this chapter will be sold in sizes from 2 to 1000 kW capacity. Larger systems can combine any desired number of modules.

3.1 Natural Gas Fuel Cell Systems

An example commercial system with a 300 kW fuel cell capacity was evaluated for installation in a convenience store/filling station open 24 hours a day. The site electrical load was assumed to average 100 kW, with 75 kW mean load during low grid prices (one-third of annual hours) and 150 kW mean load during high grid prices (one-sixth of annual hours). No use of fuel cell surplus heat was assumed. 2025 grid pricing was taken from Table 2 and natural gas price from Table 3. The fuel cell system provides whole-site UPS backup power for unlimited times. Peak site load is assumed to be slightly under 300 kW.

The system is assumed to operate in a virtual battery mode as follows. When grid prices are low, the fuel cell system is idled and site power bought from the grid at $0.067/kWh. At middle grid price, the fuel cell system powers site loads with no grid import or export. At high grid prices, the fuel cell operates at full power, with an average of 150 kW to site loads and 150 kW sold to the grid at $0.183/kWh. The virtual battery thus buys and sells 219 MWh of electricity from the grid per year. To the grid, the net apparent storage cost is only $0.116 per kWh ($0.183 - $0.067): a large savings over alternatives. Net annual energy cost savings to the user (with fuel cell system maintenance costs considered) are $40,800 in 2025.

The estimated installed cost of the 300 kW fuel cell system in 2024 is $345,000 ($1150 per kW). If the avoided cost of a backup power system ($400 per kW assumed) is deducted, net added investment (capex) is $225,000. Net annual energy cost savings are 18% of net capex in 2025.

Net investment costs will be lower for larger fuel cell systems, leading to higher ratios of energy cost savings to capex. Fuel cell system installed costs are also forecast to decline continually for installations after 2024. The ratio of electricity to natural gas prices (Tables 2 and 3) is higher for industrial versus commercial customers. A large share of commercial and industrial facilities are thus good candidates for fuel cell systems (without needing surplus heat utilization). Cost-effective systems of the type described here are expected to have capacities from 2 kW upwards. Candidate applications include cellular-phone systems.

The described fuel cell systems have all seven of the desired attributes of a virtual battery system listed in section 2.8. Net CO_2 of export power is 74% of delivered peaking turbine emissions.

Most residential natural gas fuel cell systems will be enhanced with cogeneration (heat utilization) equipment added. Such systems will normally operate continuously at maximum power to maximize financial benefits and thus will not perform as virtual batteries.

3.2 Propane Fuel Cell Cogeneration Systems

Propane fuel cell systems require utilization of most of their surplus heat (cogeneration) to make them cost-competitive with grid power and enable their cost-effective operation including a virtual battery function.

An example small commercial system with a 30 kW fuel cell capacity was evaluated for installation at a northeast Ohio site. Its annual average site load was 10 kW (at each price level). Maximum average hourly load was 30 kW (with higher surge loads for a few seconds). Surplus heat was used for year-around water heating and space heating assistance when appropriate. Annual benefits were maximized when the system was operated both as a virtual battery and as a distributed generator to the grid, as follows (low and high price periods as assumed to be independent of outdoor temperature on average).

When grid sell-to-user prices are low (one-third of annual hours), all site power is bought from the grid and the fuel cell system used only for thermal functions.

When grid buy-from-user prices are high (one-sixth of annual hours), the fuel cell system operates continuously at 30 kW, with an average of 20 kW sold and surplus heat used to the extent possible.

At middle grid price and outdoor temperature of 16ºC (61ºF) and higher, the fuel cell system operates at 10 kW to power site loads (load following: no grid import or export), with part of the surplus heat used (mostly for water heating).

At middle grid price and lower outdoor temperatures, the fuel cell system operates at 30 kW, with 20 kW sold and surplus heat used to the extent possible.

Using the Table 2 and 3 prices and a fuel cell maintenance cost of $0.012/kWh, annual net energy cost savings in 2025 were $10,820. Exports to grid are 29219 kWh/year when prices are high, equaling import kWh when prices are low (virtual battery mode). An additional 56659 kWh are sold to the grid at middle price (distributed generation mode).

Estimated installed capex in 2024 was $69,950. Avoided capex costs are $24,000 for a propane water heater and 30 kW backup power system, giving a net investment of $45,950. The 2025 ratio of energy savings to investment (ROI) is 24%.

The proposed system has all seven of the desired attributes listed in section 2.8. Net CO_2 savings are 1400 g/kWh exported (2.3 times the 600 g/kWh emissions from peaking turbines). The large cogeneration thermal benefits are responsible for the much larger net CO_2 savings versus the section 3.1 natural gas example.

3.3 Subsequent Fuel Cell Systems

After 2024, the above types of fuel cell systems are expected to sell for gradually lower prices per kW of capacity giving lower total installed costs, leading to higher returns on investment.

Advanced alternative models (with higher installed costs) are expected to later become available which capture all the CO_2 from the fuel as liquid for storage, sale, and permanent underground sequestration. These models will yield modest additional revenue from CO_2 sales and will completely eliminate fossil CO_2 emissions from site power generation.

4. Synthesis Systems

This chapter describes proposed systems with reversible solid-oxide electrochemical stacks and other equipment. Each system would be fed fuel (natural gas in 4.1, biomass in 4.2) at a constant rate. At intermediate grid prices, they would convert the fuel into valuable liquid ammonia or gasoline (with no grid power input or output). At high user-to-grid prices, the systems would operate in fuel-cell mode to produce only export power. At low grid-to-user prices, purchased power would be used for extra heat and electrolysis (splitting steam into hydrogen and oxygen) to increase liquid product yields. The systems would thus function as virtual batteries: consuming grid power when prices are low and exporting power when prices are high.

Due to their complexity, use of higher pressures, and storage requirements, the proposed synthesis systems are expected to be used at larger scales than most of the fuel cell systems described in chapter 3. The examples cited export 1000 kW and import 500 kW when grid prices are appropriate. Each module would be factory built and tested and then transported to the installation site on a single standard-size truck. Many sites would install multiple modules. The systems would produce considerable surplus heat, which could be utilized in some cases (the financial calculations below assume surplus heat is simply rejected to outdoor air).

The systems described below are based upon known technology, but will require pilot-scale development before commercialization. The cited numerical values are based on material and energy balances (not included), prices from Tables 2, 3, and Ref. 1, and other assumptions. It is expected that mature production models of both systems will be sold with capacities up to three times the examples shown (but still transportable on standard trucks).

Each system would also produce considerable surplus heat, whose value is not included in the cited margins. However, this heat might be used in greenhouses or other nearby facilities, especially from the biogasoline systems. Combination systems are also possible, which would combine synthesis functions with the continuous production of surplus power for site needs (at lower cost than purchased power). Synthesis systems could also be configured to serve as UPS systems for the site.

4.1 Natural Gas to Ammonia

Anhydrous (dry, commercially pure) ammonia is expected to sell in 2025 for about $600 per ton. Ammonia is a gas at ambient temperature and pressure, but is transported and handled as a liquid (its vapor pressure is 10.6 bar (139 psig) at 27ºC). Ammonia is used primarily as fertilizer with a smaller share used for industrial syntheses. Most ammonia is applied to farm fields directly, but some is first converted to a derivative such as urea (a water-soluble solid).

Ammonia is usually manufactured today from natural gas using long-established processes which include steam reforming, water-gas shift, gas purification, and catalytic ammonia synthesis from H_2 and N_2 gases at high pressures (often over 70 bar). Electric power is also used (primarily for compressors). Today's processes have no virtual battery function, very large capacities (and capital cost), and considerable emissions of NO_x. Their CO_2 emissions average about 1.47 tonnes (metric tons) per ton ammonia. The U.S. currently imports part of its ammonia.

The proposed new systems (installed in the U.S) would offer multiple advantages over existing systems, including the following. They will have superior operating economics and zero emissions. They will act as virtual batteries, be practical at much smaller capacities than conventional ammonia plants, and allow much faster installation and startup schedules. All carbon in the natural gas feed will be captured as pure liquid CO_2 for sale and subsequent permanent underground sequestration.

Each complete equipment module will include natural gas processing, reversible solid-oxide electrochemical stack assembly, catalytic reactors, pressure-swing-absorption (PSA) beds, heat pump, compressors, heat exchange, auxiliary equipment, and controls. Its ammonia reactors will utilize emerging advanced catalysts operating at much lower pressures than conventional plants.

Table 4 lists values for an example module and its operation (using Commercial 2025 forecast prices). Natural Gas LHV is 1506 kW and liquid CO_2 production 0.304 tonnes/hour.

Table 4. Natural Gas to Ammonia Module

Mode		Max Ammonia	Base Case	Export Power
Import from Grid	kW	**500**		
Export to Grid	kW			**1000**
Ammonia Liquid	tons/hour	**0.342**	**0.248**	
Margin	hour	**$108**	**$84**	**$119**

The Table 4 hourly margin includes natural gas cost from Table 3, grid prices from Table 2 (low for import, high for export), ammonia price of $600 per ton, and liquid CO_2 selling price of $20 per metric ton (tonne). From the utility perspective, apparent electricity storage cost remains $0.116/kWh (as cited in section 3.1).

If Max Ammonia mode occurred one-third of annual hours and Export Power mode one-sixth, the Table 4 margin would total $860,000/year. Other operating costs (labor, maintenance, property taxes, and insurance) are estimated to total $160,000 per year (per module), for a net operating margin of $700,000 per year. If the installed capital cost (capex) were $2.0 million per module, net operating ROI would be an attractive 35% of capex. Export and import grid power would each total 2192 MWh/year. Ammonia production would total 2084 tons per year, with net avoided (negative) CO_2 emissions of 3055 tonnes per year.

Some ammonia systems might be utility owned and installed adjacent to distribution substations. Such systems would benefit from minimized power distribution and fuel costs and allow the utility to directly control their power import and export timing.

4.2 Biomass to Biogasoline

This section summarizes a proposed process and equipment to convert biomass into gasoline (here called biogasoline), with grid power import or export when prices are favorable (and hence also acting as a virtual battery).

The assumed biomass feed consists of any blend of crops (such as switchgrass, poplar chips, or miscanthus grass) and wastes (such as corn stover, manure, or sorted municipal solid waste). The feed would be dried before use (probably using surplus heat from the process). Ref. 2 describes how the United States could sustainably produce about 1.5 billion tons (dry basis) per year of biomass without harming food production. Biomass has three key advantages over natural gas as a process input: it contains no fossil carbon, is renewable, and costs less (per unit of energy content). Also, its production, handling, and processing can create many new jobs.

The proposed biogasoline would be super-premium 99 octane, free from aromatics, olefins, and sulfur. The fuel would be suitable for all vehicles and for blending. It would command a premium price for both its octane and its environmental advantages (no fossil carbon). All the feed carbon not present in the biogasoline product would be captured as liquid CO_2 for sale and subsequent permanent underground sequestration. The production process would also produce saleable organic fertilizer byproduct.

The biomass-to-biogasoline converter would include a thermally integrated hot section (gasifier, reversible electrochemical stack assembly, and heat exchange), compressors, catalytic chemical reactors, heat exchangers, heat pump, auxiliary equipment, and controls. Each complete converter module would be factory built and tested and then transported to the site on a standard truck. Table 5 shows example values.

Table 5. Biomass to Biogasoline Module

Mode		Max Gasoline	Base Case	Export Power
Dry Biomass LHV	kW	**1604**	**1604**	**1604**
Import from Grid	kW	**500**		
Export to Grid	kW			**1000**
Biogasoline	gal/hr	**49.0**	**35.3**	
CO2 Liquid	te/hr	**0.19**	**0.30**	**0.58**
Margin	hour	**$113**	**$97**	**$152**

Table 5 uses estimated 2025 prices, including commercial grid prices from Table 3 (low for import, high for export), biogasoline at $3.78/gallon, dry biomass at $125/ton, organic fertilizer at $250/ton, and liquid CO_2 sales at $20/tonne. Dry biomass feed rate is 734 lb/hr and solid organic fertilizer production is 27 lb/hr.

If Max Gasoline (low grid price) mode were one-third of the year and Export Power (high grid price) mode one-sixth, the Table 5 margin would total $975,000 per year. Other operating costs (labor, maintenance, property taxes, and insurance) are estimated to total $250,000 per year, giving a net margin of $725,000 per year. If the installed capital cost were $2.5 million per module, net operating ROI would be an attractive 29%. One module would annually produce about 300,000 gallons of biogasoline. Import and export grid power would each total 2192 MWh.

Conventional gasoline from petroleum emits 10.2 kg of fossil CO_2 per gallon, so the above quantity of conventional gasoline would emit 3040 tonnes per year. The proposed process emits zero fossil CO_2 and sequesters 2740 tonnes of bio-CO_2, for a total reduction of 5780 tonnes/year.

It is expected that many biogasoline systems will be installed close to biomass sources to minimize handling, storage, and transportation costs.

4.3 Other Synthesis Processes

Synthesis systems could be configured to provide uninterruptible whole-site power in addition to their synthesis capabilities, reducing site power costs and carbon emissions.

A variant of the above process (with the same capex) could produce premium hydrocarbon biodiesel (and operate with a virtual battery function). Hydrocarbon biodiesel would be superior to today's biodiesel esters, which have poor cold weather properties. It would also be superior to existing low-sulfur diesel from petroleum, with zero sulfur and aromatics and high cetane number and lubricity. The proposed biomass-to-biodiesel process would yield fuel at the same cost (per unit of energy content) as biogasoline (and much cheaper than fuels made from vegetable-oil crops). The forecast U.S. consumption of diesel fuel in 2040 is 79% of gasoline use (energy content basis). Wholesale prices for hydrocarbon biodiesel are expected to be similar (on an energy content basis) to biogasoline. Production of biodiesel in addition to biogasoline should assist remaining petroleum refineries to balance their product ratios.

Although other variants of the above process could produce still other hydrocarbon biofuels (such as jet fuel and propane), these fuels are forecast to have lower selling prices and thus may not compete with simpler systems which continuously generate electric power from biomass using gasifiers and fuel cells.

5. Alternatives

5.1 Battery Systems

Battery-based energy storage systems can be installed at user sites (residential, commercial, or industrial) for one or more purposes. Some are used only for uninterruptible power supply (UPS) systems as cited in section 2.6. Others are incorporated (as minor components) in the advanced systems discussed in chapters 3 and 4. Battery systems are also candidates for grid-interactive operation: delivering power when prices are high and being charged when prices are low. This section discusses sizeable grid-interactive battery systems intended for frequent cycling (often every day). They could also provide UPS power to the site during grid outages.

Many different types of rechargeable (secondary) deep-cycle batteries are either available or are expected soon. The leading types are lithium-ion and lead-acid. Other types (less available and with no expected net cost advantage) include sodium, nickel-iron, and various flow batteries (which use tanks to store liquid reactants). Battery systems use multiple batteries connected in series, with larger systems having more than one series string connected in parallel. Individual batteries may contain one or more cells. All batteries suitable for use in the systems described in this section are designed for long cycle life at significant depth of discharge (DOD).

A grid-interactive battery storage system also includes power-electronic circuits for charging and discharging, mounting rack, enclosure, cabling, cooling and ventilation, interfacing contactors and switches, overcurrent protection, and a control system with data display and output. Well-designed leading-type battery systems have round-trip storage efficiencies (AC out/AC in) between 80% and 90% under normal operating conditions. Systems are designed to match site grid voltages, from 120 or 120/240 Volts for residential up to 277Y/480 Volts, 3 phase for large commercial and industrial systems. Usable energy-storage capacities range from a few kilowatt-hours upwards. Maximum sustained power outputs range from a few kilowatts upwards, with surge power capabilities (for a few seconds: limited by their inverter and not the battery bank) typically about double their sustained capacity. Battery charging is typically designed to deliver about 25% of the battery energy capacity per hour (“C/4 rate”). Many battery systems have provisions for connecting optional solar photovoltaic arrays and/or engine-generators.

Today’s installed capital cost of a grid-interactive battery system of the type described above is usually at least $600 per kWh of usable daily energy output (expected to remain similar in 2025 (in inflated dollars). Capital cost is essentially independent of system size above 50 kWh per cycle (smaller systems usually cost somewhat more per kWh of capacity). The most cost-effective daily DOD for typical systems is close to 50%. Future stationary battery systems are expected to chiefly use lithium-ion or lead-acid types, which are predicted to have similar installed system costs and storage costs per kWh delivered.

Average electricity storage cost is the sum of capital charges and battery replacement costs. Calculations by the author on a system using example lead-acid AGM (absorbed glass mat) batteries gave a total storage cost of $0.54/kWh. Lazard (Ref. 4) calculated levelized battery storage costs for commercial and industrial systems of $0.53/kWh and up (residential storage costs were greater). Neither cost includes charging energy.

The useful life of secondary batteries depends on both their discharge pattern and temperature. Smaller DOD gives longer cycle life, but requires more batteries (higher capex) for a given system output. Most practical systems use an average DOD of 40% to 50%. Batteries experience temperature-dependent internal corrosion whether they are cycled or not. A good battery cooling system can significantly extend battery life. Battery banks in U.S cell-phone buildings often operate quite hot and are replaced every year even when not cycled (a significant cost).

5.2 Heavy-Duty Gensets

Backup gensets (section 2.6) are intended for operation only during power outages and thus have limited run life between major overhauls. They cannot operate in parallel with (connected to) the utility grid.

Another type of genset (sometimes called heavy-duty type) is designed to run thousands of hours per year. Some models are designed to synchronize with the grid, allowing them to power site loads while exporting excess power to the grid (which will supply any shortfall to the loads). Commercially available units are powered by either reciprocating or gas turbine engines, fueled by natural gas, propane, or diesel fuel. Available sizes range from about 5 kilowatts to many megawatts. Heavy-duty gensets have been installed at some commercial and industrial user sites to serve two purposes: generate power when grid prices are high (to offset purchases and sell any surplus) and provide backup power during outages. Although they do not mimic all the virtual-battery functions of the chapter 3 and 4 systems, gensets which are oversized versus site loads can aid grid balancing.

A heavy-duty genset would also serve as a backup generator during outages (UPS capability would require further expenditures). Heavy-duty genset operation would create sustained noise and generate pollution (less for gas turbines).

A Capstone model C200 gas turbine was considered for on-site commercial peaking use with natural gas fuel. It has a rated output of 200 kW, a rated fuel efficiency of 33%, and a typical installed cost of about $300,000 ($1500 per kW). If high prices occurred an average of 4 hours per day, its calculated total cost of electricity (COE) is $0.222 per kWh, which is somewhat higher than both the buying and selling prices in Table 2 . However, if part of its capital cost were credited for its backup power capability, the COE would fall close to the Table 2 values and hence such an installation could be reasonable if better alternatives were not available (such as described in section 3.1).

For much larger commercial sites, gas turbine gensets from 1700 to 3500 kW are available with capital costs near $1200 per kW and fuel efficiencies near 27%. They would have a COE similar to the above.

Reciprocating heavy-duty gensets have considerably higher maintenance costs and higher noise levels than gas turbines. It is doubtful that any would be deemed cost effective versus the grid. Some reciprocating gensets are sold for use on propane or diesel fuel. Their cost of operation would be far higher than using natural gas and thus would not be appropriate for grid-connected applications in the U.S.

5.3 Other Storage Methods

A wide variety of other energy storage technologies are either in use or have been demonstrated. Their combined impact on the problem described in section 2.2 is either negligible or has been already included in one of the factors listed. Among the storage methods are the following.

5.3.1 Water Storage

Some hydroelectric facilities have associated water-storage reservoirs and equipment for extra generation. Additional water is withdrawn and sent through the turbines to generate extra power when demand is high. The reservoir is then refilled using either gravity flow (as practiced alongside Niagara Falls) or by reversing some of the turbine-generators to act as pump-motors which lift water using grid power when demand is low. The latter option is called "pumped hydro" and now accounts for about 0.05% of U.S. generation. Pumped hydro supplies the vast majority of grid electricity from storage today. Very little expansion of pumped hydro is expected in the future.

5.3.2 Compressed Air Storage

A small number of facilities exist which use low-cost power to compress air, which is stored in underground caverns. When prices are high, compressed air is withdrawn, used to combust natural gas fuel, and the hot exhaust expanded through a turbine-generator. Such a system is therefore a peaking turbine with energy storage. Very few suitable sites are known and the capacity of such systems is insignificant.

5.3.3 Thermal Storage

Thermal storage can be used in several ways to alter the timing of electricity supply or demand. The benefits of thermal storage will improve the operation of the cogeneration systems described in section 3.2. Extra hot water can be heated using low-cost power and stored in oversized tanks.

Some very large solar-thermal systems (with steam turbines) use large molten-salt tanks to store high-temperature heat during the daytime. The heat is then used to generate steam after sundown.

Electricity usage timing for space heating and cooling can be time shifted using either passive thermal storage (allowing indoor temperatures to rise and fall an extra amount) or active thermal storage. Common systems for active cold storage use ice/water tanks. Hot thermal storage can use melting and freezing of paraffin wax.

5.3.4 Miscellaneous

Electricity can be stored directly in a capacitor (electrostatic storage) or superconducting magnet (electromagnetic storage). Both are far too expensive for significant grid use. However, capacitors and ordinary (ambient-temperature) inductors are essential components in virtually all power-electronic circuits such as DC-to-AC inverters. Double-layer capacitors (known as super capacitors or ultracapacitors) are practical for some very small storage applications.

Flywheel systems have been demonstrated at various sizes, but are much too costly for the uses discussed here.

6. Benefits

6.1 Capacities

The suggested U.S. virtual battery capacities (section 2.8) might be achieved using the values in Table 6. The export (to the grid) capacity and energy figures in the table refer only to periods of high grid prices (the cogeneration systems export additional power at middle prices).

Table 6. Example 2050 Virtual Battery Systems

System Type		Natural Gas Fuel Cell	Propane FC Cogeneration	Ammonia	Biogasoline	Total
Export Capacity	GW	**132**	**55**	**5**	**198**	**390**
Export Energy	billion kwh	**193**	**80**	**8**	**289**	**570**
Total Useful Outputs	billion kwh	**772**	**395**	**50**	**1852**	
Market Size	billion kwh	**5700**	**5700**	**74**	**5567**	
Market Share		**14%**	**7%**	**67%**	**33%**	
Capex	billions	**$168**	**$107**	**$9**	**$420**	**$704**

Although ammonia has relatively small market, its process is expected to be commercialized earlier than the biogasoline process. Table 6 ammonia production is 11.3 million tons per year. The total capex costs shown in Table 6 are somewhat lower per kW of export capacity than the examples in chapters 3 and 4 due to the expected decline in installed costs after 2024.

As noted in section 2.8, 570 billion kW/year is 10% of expected total 2050 generation required. Supplying this energy in one-sixth of annual hours gives average power of 390 GW (about one-fourth of expected 2050 U.S. nameplate generation capacity).

The sum of the first two columns is 20.5% of U.S. electricity use, which appears to be a reasonable share of the expected 2050 mix of generation sources. The new ammonia process is expected to dominate the domestic market.

The biogasoline column includes both biogasoline and hydrocarbon biodiesel, which are expected to have similar costs and pricing. The conservative market share allows for ongoing petroleum use and additional biofuel systems without virtual battery capabilities. The listed production is the equivalent of 58.9 billion gallons per year of biogasoline. This production would replace predicted net 2050 imports of petroleum and its products (Ref. 1) with net exports.

The total capex shown averages about $28 billion per year over 25 years. Further discussion of installation timing is given in chapter 7.

6.2 Financial Benefits

The 2025 returns on investment shown in the chapter 3 and 4 examples will be higher by 2050, since expected capex values decrease with time, while net annual profits are expected to change little. Table 7 shows expected annual (pretax) profits to owner-operators of the four types of virtual-battery systems.

Table 7. Owner 2050 Profits

System Type		Natural Gas Fuel Cell	Propane FC Cogeneration	Ammonia	Biogasoline	Total
Capex	billions	**$168**	**$107**	**$9**	**$420**	**$704**
ROI		**21%**	**28%**	**41%**	**34%**	**30%**
Annual Profits	billions	**$35**	**$30**	**$4**	**$143**	**$212**

As will be discussed in chapter 7, a variety of different ownership and financing alternatives are expected for virtual battery systems. As the table shows, all have very attractive returns on investment.

The use of the proposed systems will provide valuable additional benefits as summarized in Table 8.

Table 8. Benefits 2050 Summary

	billions
Owner Profits	**$212**
Ratepayer Savings	**$99**
Biomass Profits	**$39**
Utility Savings	**$18**
Sum	**$368**

The use of the proposed virtual battery systems is expected to reduce delivered electricity costs by 10% of the $1170 billion forecast in section 2.1. This savings is allocated in Table 8, with 85% to ratepayers and 15% to utilities. Biomass profits are estimated at 30% of their 2050 average value (637 million dry tons at $205 per ton delivered). Not included in Table 8 are additional profits from maintenance parts and services for the installed virtual battery systems. The Table 8 annual total is 53% of the total capex.

6.3 Fossil CO_2 Emissions

As noted in section 2.1, forecast 2050 U.S. energy-related fossil CO2 emissions are 5.17 billion tonnes. The proposed virtual battery systems are calculated to reduce this total by 1.31 billion tonnes, a 25% reduction (1.15 billion tons of this total is from the biogasoline systems). Reference 5 describes other technologies which could further reduce net fossil CO_2 emissions to zero by 2050.

7. Discussion and Conclusions

7.1 Discussion

7.1.1 Storage Costs

The approximate cost to the electric utility of using virtual batteries at user sites is the difference between their high buy-from-user price and their low sell-to-use price. Table 9 lists these differences in 2025 (from the Table 2 values) and in 2050 (using author extrapolations).

Table 9. Virtual-Battery Storage Costs per kWh

	2025	2050
Residential	**$0.125**	**$0.206**
Commercial	**$0.116**	**$0.184**
Industrial	**$0.090**	**$0.150**

All of the 2025 virtual-battery storage costs are less than 60% of the example delivered costs of peaking power from an example gas turbine (section 2.5). They are less than one-fourth of the projected cost of conventional battery storage systems, such as lithium-ion or lead-acid (section 5.1). The cost ratios of virtual-battery storage to these alternatives is expected to change little by 2050.

Comparing the 2025 Table 9 storage costs with the Table 2 Grid Sell to User High prices shows residential storage cost at 51% of price, commercial 58%, and industrial at 67%. Since retail power from storage will be only a fraction of sales, these ratios are favorable for virtual battery use.

The simple mean of the 2050 Table 9 storage costs is $0.180/kWh. The weighted-average retail price of electricity in 2050 is projected to be $0.215/kWh (section 2.1). If 10% of that power is from virtual batteries (as assumed in chapter 6), storage costs are $0.018/kWh averaged over all power (8.4% of $0.215).

7.1.2 Utility Generation Mix

The actual U.S. generation mix in 2040 and 2050 may differ significantly from the Table 1 DOE forecast. The share of nuclear may be much lower due to lower-cost alternatives plus concerns about safety, waste disposal, and vulnerability to sabotage. Advanced plant designs using coal or natural gas, with zero carbon emissions and attractive costs (see Ref. 5), could lead to their larger contribution. The availability of the virtual batteries proposed herein could enable larger contributions from solar and wind (which are predicted to become the lowest-cost means of generation at favorable sites). Greater use of plug-in vehicles than assumed by DOE could further increase total electricity consumption.

7.1.3 Quantities and Prices

Although the above examples assume one-fourth of annual grid electricity at low prices (delivered in one-third of annual hours) and one-fourth of the electricity at high prices (delivered in one-sixth of annual hours), these fractions are not required for satisfactory virtual-battery operation or profitability. The annual quantity of low-priced electricity can be either higher or lower than high-priced at a given user site. The fraction of middle-priced power can differ from the one-half assumed. Using the example prices, virtual battery operation at high grid price is the most profitable mode and thus a greater quantity will increase profits.

The example prices used herein are expected to vary considerably with location in the U.S. Each of the three average price ratios to local averages will probably differ from the examples. Buy-versus-sell pricing will probably differ from the examples. Hourly actual prices could vary considerably from category averages. Overall average prices will probably differ from DOE forecasts. The benefits from the quantity of virtual batteries assumed will reduce expected user prices in 2050 by a projected 8.5% as shown in section 6.2. *The cited excellent financial benefits will remain attractive even with significantly different pricing.*

7.1.4 Virtual-Battery System Ownership

A variety of ownership and financing schemes for the proposed virtual battery systems are expected to coexist. Some will be owned by their operators, some by utility companies, and others by third parties. The good projected returns on investment will facilitate the large investments needed. Leasing plans (many including maintenance) will be attractive to some operators. Systems owned by utilities could have their power dispatched directly by the utilities, giving them rapid control of the timing of imports from and exports to the grid.

7.1.5 Backup Power

All the systems described can provide uninterruptible backup power to the user site, thus justifying a credit on their capex which increases their ROI.

In some cases, the utility could configure the grid adjacent to one or more virtual battery systems to allow islanding or microgrid operation during power outages (opening contactors to disconnect the island from the grid). In this mode, the virtual batteries (with their outputs properly synchronized) could supply power to a local group of users and thus provide a valuable added service.

7.1.6 Timing

Beta-test virtual battery systems are expected late in this decade, with the synthesis systems after the fuel-cell systems. Production is expected to rapidly ramp up once the benefits have been conclusively demonstrated. The average annual capex cited in section 6.1 might be reached late in the 2020s, with higher rates subsequently.

7.1.7 International

Although this paper has limited discussion to the United States, an even larger potential also exists for the systems described in the rest of the world. Direct exports, joint ventures, and licensing would facilitate expansion worldwide.

7.2 Implementation
A detailed plan to implement the deployment of the virtual-battery systems is needed.

TMI has been developing solid-oxide fuel cell technology since 1991 and has demonstrated all of the necessary elements of the proposed fuel cell and cogeneration systems. TMI owns multiple patents and a significant body of proprietary technical know-how. It has also performed detailed cost projections. The remaining technology development work is considered low risk: primarily detailed design of multiple product models and ongoing cost reduction.

The proposed synthesis systems can be introduced after fuel cell and cogeneration systems manufacturing have achieved profitability. These systems are based on extensive thermodynamic and engineering calculations, but will require a significant development effort before commercialization. Small-scale laboratory demonstrations will be a prerequisite to field testing and quantity manufacture.

The business-development section of the implementation plan will describe a phased program of financing, recruiting, field demonstrations, and early manufacturing. Collaborative development and manufacturing partnerships with TMI will be proposed.

7.3 Conclusions
Electric utilities have two sizeable problems, which are getting worse as more solar and wind generation is added. Their available total electric power supply is sometimes larger and sometimes smaller than aggregate customer demand. Both problems reduce hourly profits, sometimes to below zero. The utilities are increasingly using time-of-use pricing to encourage customers to shift their load profiles, but the effects of such pricing are limited. Existing options for the storage of electricity either have far too little capacity (e.g., hydroelectric storage systems) or are far too expensive (e.g., battery systems).

When supply exceeds demand, several strategies are now employed which tend to significantly lower utility profits. When demand exceeds supply, peaking gas turbines are the principal answer, often yielding delivered-electricity costs higher than selling prices. Utilities must boost their average retail prices to earn adequate overall profit in spite of necessary operation with the above two problems.

Four types of virtual battery systems are proposed in this report. They can buy excess electricity from the utilities at prices profitable to the utilities. They can also supply electricity to the grid at prices lower than peaking power turbines. They provide total flexibility of both the quantities and timing of energy inputs and outputs (unlike other storage systems).

The large-scale deployment of virtual battery systems is projected to generate about $370 billion/year of combined financial benefits in 2050 after cumulative investments of about $700 billion. The benefits include about $100 billion/year of electric ratepayer savings (an 8.5% reduction). The proposed equipment would also provide uninterruptible power to users, reduce U.S. energy-related fossil CO_2 emissions by 25%, and replace net petroleum-related imports with exports.

8. Appendix

8.1 References

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2. U.S. Billion-Ton Update, U.S. Department of Energy, 2011, ORNL/TM-2011/224

3. Lazard's Levelized Cost of Energy Analysis-Version 10.0, December 2016, www.lazard.com

4. Lazard's Levelized Cost of Storage Analysis-Version 2.0, December 2016, www.lazard.com

5. United States Energy 2050, Dr. Robert C. Ruhl, March 2016, www.robertruhl.com

8.2 Abbreviations and Glossary

AC	Alternating current, 60 Hertz
bar	Unit of pressure = 10^5 Pascals or 14.5 lb/in^2
CF	Capacity factor (generation energy/maximum possible)
capex	Capital expenditure (installed cost)
COE	Cost of electricity per kilowatt-hour
cogeneration	Generation of electric power plus usable heat
CO_2	Carbon dioxide
DOD	Depth of discharge of a battery
DOE	United States Department of Energy
EIA	Energy Information Administration of DOE
g	Gram
genset	Engine-generator set
GW	Gigawatt = 1000 MW or 1 million kW
HHV	Higher heating value, with water vapor condensed
hydro	Hydroelectric
kg	Kilogram = 1000 g = 453.6 pounds
kW	Kilowatt = 1000 Watts
kWh	Kilowatt-hour (one kW for one hour)
LF	Load factor (energy consumption/(peak power times time)
LHV	Lower heating value, with water vapor not condensed
MW	Megawatt = 1000 kW
MWh	Megawatt-hour = 1000 kWh
NO_x	Nitrogen oxides
PV	Photovoltaic (solar)
psig	pounds per square inch gage (above atmospheric)
Ref.	Reference (see section 8.1)
ROI	Return on Investment (annual)
sequester	To permanently store underground
T&D	Transmission and distribution of electricity
TMI	Technology Management Inc.
ton	Short ton = 2000 pounds
tonne	Metric ton = 1000 kg
TOU	Time-of-Use electricity pricing
yr	Year