CHP Program Design: Cost Benefits of Dispatching versus Baseline Operations

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ABSTRACT

There are a host of issues involved in enabling Combined Heat and Power (CHP) and clean distributed generation to compete in the market for electric power services. These issues include interconnection, tariffs, permitting procedures, volatile cost of natural gas, deciding between dispatched or baseline modes of operation and unwillingness of third party financers to fund dispatched operations. This paper will investigate the interrelations among these issues in making a CHP installation more economical.

The analysis will begin with comparing both base-lined and dispatched modes of operations. In the base-loaded mode, the CHP system is interconnected to the electrical grid and sized to meet the site's base-load requirements. However, in dispatched mode, the CHP system is operated using an approach that factors in the value of purchased power and boiler fuel costs relative to cogeneration system fuel and maintenance costs and the degree of waste heat recovered. If the CHP system has electric capacity that exceeds the industrial facility's energy needs, this excess capacity can be sold to the wholesale market when prices are favorable.

The key metric that would be used to compare the two modes of operation will be spark spread. Spark spread is the ratio between the selling price of electricity and the cost of natural gas. High spark spreads generally support CHP development, while low spark spreads generally hinder CHP adoption. The paper will also discuss the dependence of spark spreads on natural gas demands by local industry, its availability and the type of electrical generating technologies used by electric utilities.

Introduction

There are a host of issues involved in enabling CHP and clean distributed generation to compete in the market for electric power services. These issues include interconnection, tariffs, permitting procedures, volatile cost of natural gas, deciding between dispatched or baseline modes of operation and unwillingness of third party financers to fund dispatched operations. This paper will investigate the difference between dispatched and non-dispatched modes of operation and the factors that play an important role in the decision making to make a CHP installation more economical.

Economic dispatch is a very straight forward concept. Section-1234 of the Energy Policy Act 2005 (Office of Electricity Delivery and Energy Reliability 2005) defines economic dispatch as "The operation of generation facilities to produce energy at the lowest cost to reliably serve the customer, recognizing any operational limits of generation and transmission facilities." Not only the lowest cost but a number of other considerations must be addressed to ensure that the resulting system operation is secure and as well as reliable. This paper will focus on the process of economic dispatching along with the factors that constrain and complicate it.

As stated above, CHP economics and the extent to which it will impact utility service areas depend on a complicated interaction of customer electric and thermal loads, rate structures, CHP technology characteristics, natural gas prices, interconnection and regulatory requirements and incentive programs. The spark spread would be used to find out an interrelationship between all these issues and also as the key metric to compare the dispatched and non-dispatched modes of operation. The paper will also discuss the dependence of spark spread on natural gas demands by local industry, its availability and the type of electrical generating technologies used by electric utilities

Traditional Definition of Spark Spread

Traditionally, spark spread reflects the difference between the average cost of utility supplied power and the cost of natural gas. (Bourgeois et. al. 2003.)

Traditional Spark Spread = Utility Price ($/kWh) – Natural Gas Cost ($/kWh)

Positive spark spreads generally support CHP development, while negative spark spreads generally hinder CHP adoption.

Traditional Spark Spread Misrepresent CHP Economics

To explain how traditional spark spread misrepresents CHP economics, an example of a spark spread calculation is shown below.

Let us assume that the cost of natural gas is $6.5/ MMBtu and an electric generation efficiency of the prime mover is 35%. Hence the onsite generation cost becomes $0.063/ kWh. The spark spread has to be large enough to pay for the generator and its installation; an installed cost of $500/kW requires an additional $0.014/kWh to achieve a payback in four years. Thus, spark spread analysis suggests that a utility electric price of at least $0.078 is required to make CHP an attractive option under these circumstances.

There are two serious problems with spark spread calculations shown above:

a. Average prices in the calculations do not reflect customer avoided cost of electricity purchases which depend on the customer’s electric hourly loads and typically complicated rate structures, and
b. Traditional definition of spark spreads do not take into consideration the utilized waste heat created during the generation process.

Therefore, it is necessary to modify the traditional definition of spark spread.

Correct Definition of Spark Spread

The actual “Spark Spread” should refer to the difference between the price of power in the wholesale market at pre-defined time blocks and the cost of fuel and other variable operating costs, converted at a given generation plant’s heat rate to a consistent $/ kWh. The spark spread measures the variable operating margin of a given generation facility as a function of:

- The wholesale price of power less (in $/ kWh)
- The cost of fuel and other variable O&M (converted to $/ kWh)

- With the conversion factor being the plant's effective heat rate and utilized waste heat.

The new definition of the spark spread can dramatically change site economics. If, in the example above, a CHP uses half of the waste heat created in the generation process (thereby replacing natural gas purchased for space heating, etc), the cost of onsite generation is reduced by $0.02/ kWh requiring a utility price of $0.058 or less to keep utility power competitive (given the gas price, equipment costs and the four year payback requirement in the example).

To simplify the spark spread analysis, it is better to separate implementation cost and other invariable expenses over a specific payback period ($/MWh). These constant expenses can be defined as a threshold spark spread. Hence, for better economics, normal spark spread should be equal to or greater than the threshold spark spread of the plant.

Non-dispatched and Dispatched Modes of Operation

After re-defining the spark spread, one should be able to make the decision about dispatching or base-loading the power generating unit. Obviously, a positive spark spread (more precisely, a spark spread above the threshold value) is not the only decision making factor but there are number of other factors which are equally important and should be taken into consideration. These factors are listed in the last section of the paper.

In the non-dispatched mode of operation, the CHP system is interconnected to the electrical grid and sized to meet the site's base-load requirements. Even if the spark spread is negative, electricity is generated on the site itself. Most small scale power systems are envisioned as operating in a base loaded mode (running 24/7) and permanently removing the load from the grid. Where possible economically, this is a good application and serves to reduce the required capacity of the grid, theoretically reducing the number of large power plants needed to support a power pool. It is increasingly obvious, however, that base loaded power plants lose money much of the time. It can be easily proved that many power plants operate in a profitable mode only a few days a month. A good example of non-dispatched CHP would be Rutgers University's Cogeneration System which will be discussed in the next section in detail.

In dispatched mode, the CHP system is operated using an approach that factors in the value of purchased power and boiler fuel costs relative to cogeneration system fuel and maintenance costs and the degree of waste heat recovered. If the CHP system has electric capacity that exceeds the industrial facility's energy needs, this excess capacity can be sold to the wholesale market when prices are favorable. The dispatched mode of operation can be classified into two broad types (Muller 2005). The first would be daily economic dispatching where a system might run only a few hours a day when "real time pricing" of electricity makes the spark spread favorable. The second would be seasonal dispatching, where either the industrial operation is seasonal in nature (agriculture being the best example), or with combined cycle operations where steam power is used when space heating is not needed. In response to the volatile wholesale market, very recently Princeton University together with Icetec, Inc. developed a real-time economic dispatch system. Their model predicts campus energy demands, compares the cost of on-site generation to purchased power, and recommends the most cost-effective combination of equipment for operators to use to meet those requirements.

Non-dispatched and Dispatched Mode Case Studies

Non-dispatched Mode of Operation: Rutgers Cogeneration Facility

Rutgers University of New Jersey is located on three regional campuses: New Brunswick/Piscataway, Camden, and Newark. A central plant has provided district heating at Rutgers University in Piscataway, NJ since 1950. The University completed the Busch Cogeneration Plant in December 1995 to economically meet the needs of an expanding campus. The system which is non-dispatched provides electricity, hot water, steam for campus laboratories and dining hall-serving lines, and district cooling using absorption chillers (Utilities Department 2001).

Table No. 1. Rutgers University Cogeneration Plant Operating Data

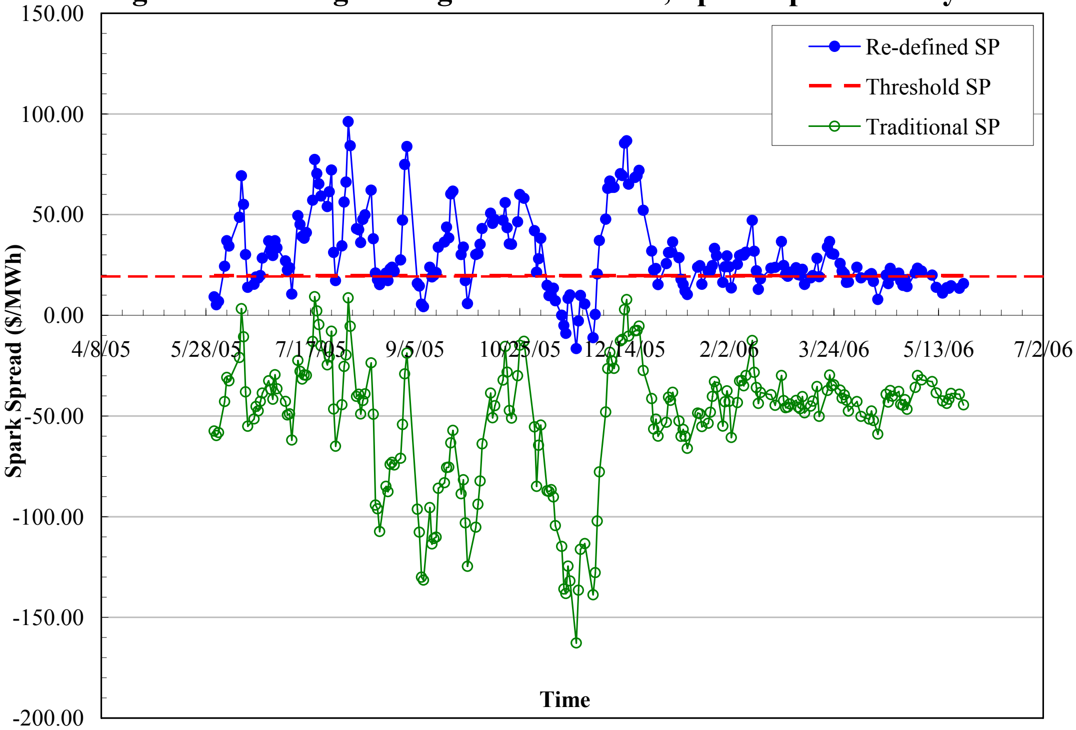
Project Design Capacity (MW)	14 (Three Solar Centaur-50 Turbines)
Power to Heat Ratio	0.5
Total Net Efficiency (HHV)	73%
% Fuel Savings	9% (1,900 metric tons of carbon)
% NOx Decrease	66% (150 tons)

The old central heating plant consisted of one 50 MMBtu/hr and two 100 MMBtu/hr high temperature water heaters primarily fueled by natural gas. The system also contained two 250 kW backup diesel generators to provide emergency power to the heating plant. To meet increasing heating demand Rutgers chose to co-generate because of the efficiency and cost savings. They added three Solar Taurus-60 gas turbines with three heat recovery high temperature water heaters (HR-HTWH), which together produce up to 14 MW of electric power and 75 MMBtu/hr of heat. When needed, duct burners produce an additional 75 MMBtu/hr of thermal energy increasing the total thermal output of the turbines to 150 MMBtu/hr. The resulting facility is an integrated plant with a heating capacity of 400 MMBtu/hr. The heat generated maintains 250,000 gallons of water in the closed-loop high temperature hot water system at a nominal temperature of 370°F. The entire high temperature water heater (HTHW) system is maintained at 150 psig (above the saturation pressure) to prevent boiling in the system. The water is then piped to campus buildings using four zone pumps.

Spark spread analysis for the Rutgers Cogeneration Plant is shown in the Figure No.1 (Natural gas and electricity data for 220 days). Electricity pricing for the PJM Interconnect region is taken from NRGSTREAM website and natural gas pricing data is taken from the Federal Energy Regulatory Commission (FERC) website. In Figure No.1, filled circles are showing re-defined spark spreads, while empty circles are showing traditional values of spark spreads, and a dashed constant line is representing a threshold value of spark spread.

Based on the total implementation cost and five years of payback time, the threshold value of spark spread for the plant is equal to \$19.8/MWh. During the year 2005-06, spark spread for Rutgers Cogeneration Plant was above the threshold spark spread for 69% of the time (151 out of 220 days) and remaining time it was below the threshold value.

Figure No.1. Rutgers Cogeneration Plant, Spark Spread Analysis



That means 31% of the time (69 out of 220 days) the plant was not making any profit or saving the money and it could have been beneficial for the Rutgers to buy the electricity from the utility company rather than generate it on-site.

Dispatched Renewables and Dispatchable CHP Example: Township of NJ Cogeneration and Renewable Energy Project

Without directly acknowledging it, the power grid is already accepting dispatched power from renewables. Wind and solar plants are non-dispatchable as they are already dispatched by the "God". If renewables are independently harnessed then it becomes a very simple decision problem but if they are combined with a cogeneration system, it becomes a very complicated optimization problem.

An excellent example of dispatched renewables and dispatchable CHP would be the Township of New Jersey Cogeneration and Renewable Energy Project. This project will employ multiple electric generation technologies as part of an integrated campus district energy system. Together, the CHCP (Combined Heat, Cooling and Power) and solar electric systems will supply 97.8% of the campus' electricity. Taking into account the solar electric production, the cogeneration system will have a load factor of 61.2%. While the solar electric system reduces the engines' operating hours, the integrated energy system is first and foremost designed to maximize the complementary benefits of clean renewable electricity and efficient onsite cogeneration.

The CHCP control system will serve as the main load-balancing source for the campus and will balance the load with the 600 kW solar electric system, the engines and the grid. The system will optimize based on load and economic factors. The 800 KW CHCP will run in both grid-connected and grid-independent modes of operation. When the grid becomes unavailable, the system will be capable of automatically switching to independent, load-following operation.

Table No. 2. The Township of NJ Cogeneration and Renewable Energy Project

Project Design Capacity (MW)	0.8 (2 Schmitt Enertec Gas Engines)
Power to Heat Ratio	0.64
Total Net Efficiency (HHV)	82%
% Fuel Savings	-
% NOx Decrease	90% (1.58 tons)

The control system for this project will be the first of its kind – it will be specifically suited to the unique challenges of integrating a non-dispatchable renewable resource (the photovoltaic system) with a dispatchable cogeneration system. The controls system will use historical consumption data combined with real-time information, and data from the photovoltaic system to calculate whether it is best to generate electricity with the CHCP system or purchase electricity from the grid. In this way, the control system will optimize the efficiency and economic performance of the campus' integrated energy infrastructure. Based on the total implementation cost and five years of payback time, threshold spark spread for the Township of NJ Cogeneration and Renewable Energy Project is equal to $25.8/MWh. Based on the electricity and natural gas data for the year 2005-06, spark spread for the plant could have been above the threshold value for 54% of the time (118 out of 220 days) and remaining time it was below the threshold value (See Figure No.2). 46% of the time (102 out of 220 days) the plant would not be making or saving money. During this time, it could have been beneficial for the Township of NJ to buy the electricity from the utility company.

Figure No. 2. Township of NJ, Spark Spread Analysis

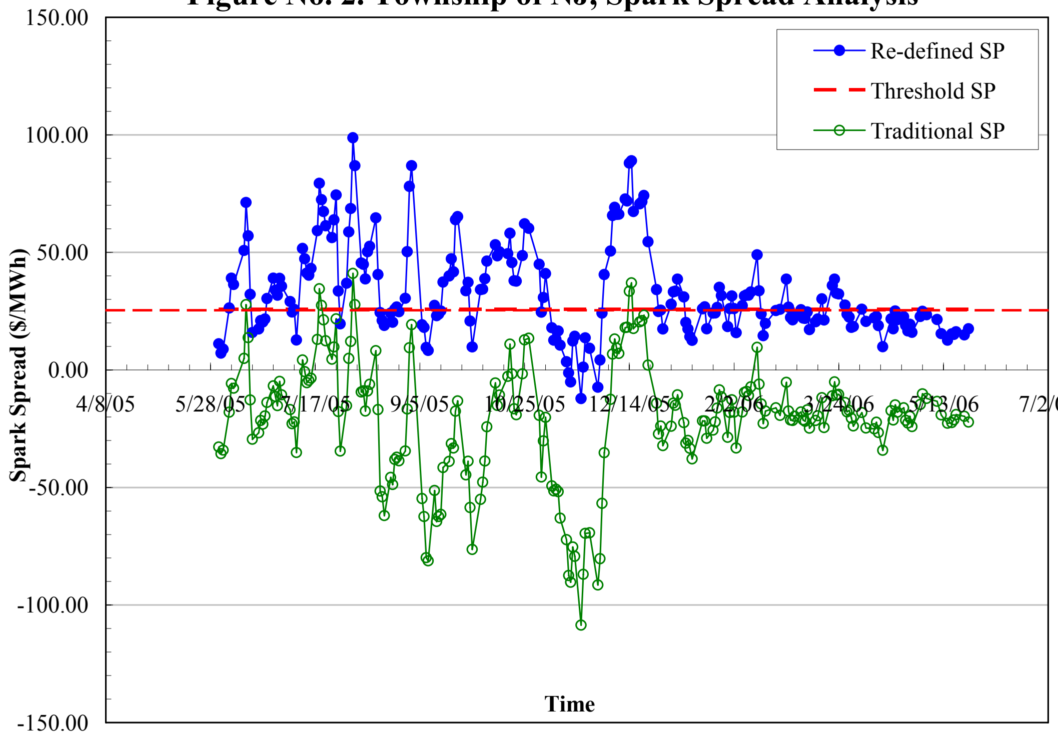


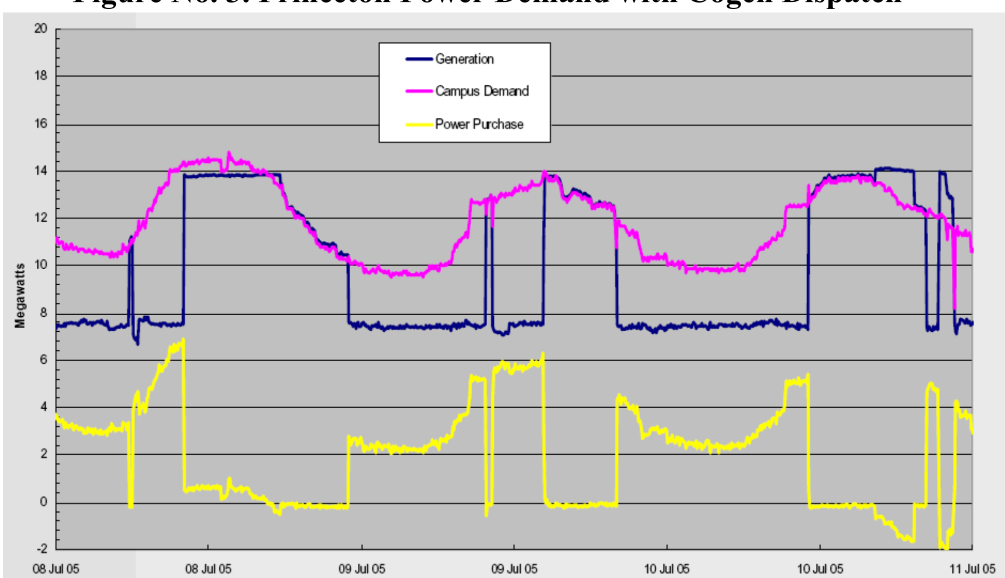
Table No. 3. Township of NJ, Cogeneration Plant Economic Performance

Total project cost	$8.93 million dollars
CHCP cost	$2.05 million dollars
Total energy savings per year	$385,000 / year
Annual savings due to CHCP	$100,000 / year

Dispatched Mode Example: Princeton University Cogeneration Facility

Princeton University's major challenge was how to match the power, steam, and chilled water demands to plant assets economically at any point in time, while dealing with volatile power/ gas market and adhering to the business rules and operational constraints. In response to the volatile wholesale market, a real-time economic dispatch system (see Figure No.3) was developed by Princeton and Icetec, Inc. (Nyquist and Webster. 2006). It predicts campus energy demands, compares the cost of on-site generation to purchased power, and recommends the most cost-effective combination of equipment for operators to use to meet those requirements. The model inputs include real-time data for weather, NYMEX gas and oil prices and futures, campus energy demands, equipment efficiencies and availability. Using this system allows the plant operator's focus to shift from simply meeting demands to delivering energy in the most cost-effective manner.

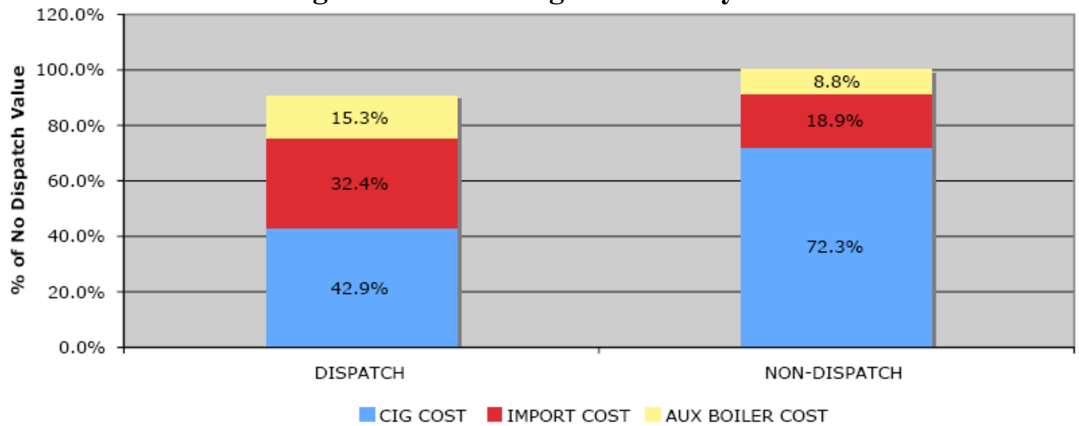
Figure No. 3. Princeton Power Demand with Cogen Dispatch



Reference: Princeton University Utility Department

While this system could be fully automated, Princeton chooses to use it as an expert recommendation to plant operators who can also take into account reliability issues such as local storms and campus events. Based on the limited operational period to date (approximately $28,000 saved in November), annual savings are projected at $500,000 to $800,000 (See Figure No.4).

Figure No. 4. Weighted Cost by Fuel Source



Reference: Princeton University Utility Department

Economic Dispatching: An Optimization Problem

Many factors influence economic dispatch in practice. These include contractual, regulatory, environmental, scheduling, unit commitment, and reliability practices and procedures. Because economic dispatch requires a balance among economic efficiency, reliability, and other factors, it is best thought of as a constrained cost-minimization process (Chapa et al. 2003). Without considering these types of limitations economic savings achieved during one period of time may be far outweighed by the cost associated with economic penalties associated with non-compliance or debt repayment.

Long-term Fuel Constraints

- Gas generating units may be subject to energy-limits, in the form of minimum and maximum daily takes of the total gas used at a generating station. Such daily energy limits can also exist for other types of generating units. If the particular unit goes beyond its daily limits it may not be available for dispatching.
- Take-or-pay contracts: These contracts are multiple year contracts that include take-or-pay clauses, under which pipeline companies (or other purchasers) are obligated to pay for contract volumes, whether they utilize the gas or not. In this situation, the unit will keep running no matter what the spark spread.

Long-term and Short-term Emission Constraints

Constraints such as air permit limitations and short-term to real-time NOx or SO2 emission constraints exist. Units that use up their emission allowances prematurely may not be available to dispatch during peak periods.

Equipment Limitations (Life, Start-up Time and Cost)

- Each generating unit has a 'no-load' or fixed operating cost and a number of incremental operating costs, which can define a nonlinear profile of operating costs. If economic dispatch extends into longer horizons of time, the recovery of installation costs of generation may need to be included in the price signal for each resource.
- Each generating unit has either a single start-up cost or a number of warmth-dependent start-up costs corresponding to a number of warmth conditions of each generating unit (e.g. hot, warm, cold) as determined by the time that unit has been off-load. Each generating unit can have minimum on and off times. At the same time, there can be upper limits on the numbers of start-up events of each generating unit.
- There can be 'station synchronizing intervals' and 'station desynchronizing intervals' at some generating stations. These are minimum time gaps between the start-ups and shut-downs of generating units at the same generating station.

Transmission Losses

Transmission should also be considered in economic dispatch. Recent experiences in the market have seen loss charges and uplift charges that negate the economic dispatch savings calculated in the real time horizon.

Crew Burden or Responsibilities

Power generating stations require engineers, operators, supervisors and workers to keep it running smoothly without any interruptions. Most of the crew members work around the year and with particular pay structure. If economic dispatching is going to keep the plant off for approximately 50% of the time either the facility is going to pay its crew for nothing or to use them in some other projects. Seasonal dispatching is a better option to take care of the crew burden.

Reliability Issues

Because economic dispatch incorporates security and reliability considerations and constraints, it promotes and improves grid reliability. Using economic dispatch allows the operator to deploy resources more efficiently and thus handle higher peak loads more reliably than would be possible without. Economic dispatch, combined with Locational Marginal Pricings (LMPs), makes reliability needs clear and transparent to everyone in the region and the market. Because LMPs are highest where the need for power is greatest, they immediately reflect the impact of grid conditions such as transmission bottlenecks, peak loads, or generating units losses, and create an incentive for every market participant to respond by supplying power (or reducing load) where most needed. No research suggests that economic dispatch, as currently practiced, might compromise grid reliability.

Conclusions

1. Except some regulatory and reliability issues, under most of the circumstances dispatched mode of operation is more profitable than the base-loaded mode of operation.
2. Spark spread should be used as the key metric to compare between dispatched and non-dispatched modes of operation.
3. Traditional spark spread misrepresents the CHP economics as it takes into consideration average prices of electricity as compared to actual prices charged to the customer. It does not take into consideration the utilized waste heat created during the generation process. Hence, it is necessary to re-define spark spread to use it competently in decision making.
4. CHP economics and the extent to which it will impact utility service areas depends not only on the spark spread but also on a complicated interaction of customer electric and thermal loads, CHP technology characteristics, crew burden or responsibilities, interconnection and regulatory requirements and incentive programs.

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