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INCORPORATING FLEXIBILITY IN UTILITY RESOURCE PLANNING

A WHITE PAPER BY WÄRTSILÄ AND ENERGY EXEMPLAR





INCORPORATING FLEXIBILITY IN UTILITY RESOURCE PLANNING

INDEX

Executive summary	4
1 Introduction and motivation	5
2 Capacity expansion modeling, past and present	7
3 Comparing the new and the old	10
4 Defining the utility	15
5 New build capacity options for comparison of LDC and Chrono capacity expansion models	16
6 Comparison of Outcomes from Chronological vs. LDC Capacity Expansion Models	17
7 Capacity Options – How to Value Increased Diversity and Flexibility	20
8 Summary and Moving Forward	28
References	31
Appendixes	
1 Information on the Utility used for this Study	32
2 Transmission Pricing	35
3 Parameters for Gas-Fired Generation used in Simulations	37

INCORPORATING FLEXIBILITY IN UTILITY RESOURCE PLANNING

EXECUTIVE SUMMARY:

The trend of increasingly variable net load is characteristic of all power systems with increasing penetration of wind and solar energy. As the amount of renewable energy increases, decreasing minimum net loads and increasing net load ramps require more frequent starts and stops, ramps and cycling, all of which impose costs and stress on the dispatchable generation fleet. Operational flexibility is needed to cope with varying net load.

Electric utilities engage in Integrated Resource Planning (IRP) to determine the optimal investments in new generation assets. At the core of IRP efforts are capacity expansion models. These models have historically used a mathematical simplification based on a Load Duration Curve (LDC). The LDC arranges the net load in a simple descending order (e.g., hourly, daily) with no information on ramp events and cycling. As a result, the new capacity selections are not optimized for flexibility needed to meet net load variability. To make up for deficiencies, the typical approach is to apply significant post-analysis approaches, where flexible capacity is added outside of the optimization framework. This implies the resultant fleet is suboptimal, capable of meeting net load fluctuations but at a higher cost than necessary. In this work, we illustrate a state-of-the-art alternative called Chronological modeling, designed to select capacity with the appropriate capabilities in the first place. We then use this approach to quantify the value of flexible capacity as a means to reduce total system costs.

We compare the outcomes of traditional LDC and Chronological modeling for a utility with aggressive renewable penetration. The traditional approach underestimates annual operational costs by 7%. These errors result in an underestimation of future cost of electricity. Similar errors from the Chronological simulations were less than half that of the LDC approach.

Using the Chronological approach, we compare a base scenario where all new build choices are gas turbines (GT) in simple and combined cycle, versus a flex scenario that includes the same lineup but now adding more flexible options in addition to GT based capacity. By “more flexible” we are referring to capacity options with incremental modularity, faster start times, lower start costs, higher ramp rates and improved efficiencies. The flex scenario yielded a final buildout that could meet utility load obligations with 9% less capacity and 870 MUSD less cost across the horizon of the analysis. Savings were due primarily to fleet optimization effects, where the full potential of the most efficient units are unlocked as flexible assets attend to net load fluctuations. Detailed dispatch analyses of the fleets (base vs. flex) shows the flex scenario yields 64 MUSD/year operational savings coupled with 1.5% reduction in CO₂ emissions.

1. INTRODUCTION AND MOTIVATION

Integrated resource planning is a crucial part of long-term planning for utilities, municipalities, electrical cooperatives and national agencies. At the heart of resource planning efforts are capacity expansion models, which solve for the optimal mix of capacity (MW) to install over the next 10, 20 or more years. The optimal solution is the one that presents the least cost and is less sensitive to differences in assumptions than alternatives. Traditionally, this is considered a point in the “efficient frontier”, a careful examination of multiple potential outcomes, with emphasis given towards solutions that provide the lowest cost for an acceptable level of risk.

Capacity Expansion Models (CEMs) are generally found in software packages such as Ventyx Strategist (PROVIEW)[™], EPIS AuroraXMP[™], SDDP OptGen[™], and others. These packages make use of something called the Load Duration Curve (LDC), a mathematical simplification that makes the computational burden of obtaining solutions tractable (Figure 1.1).

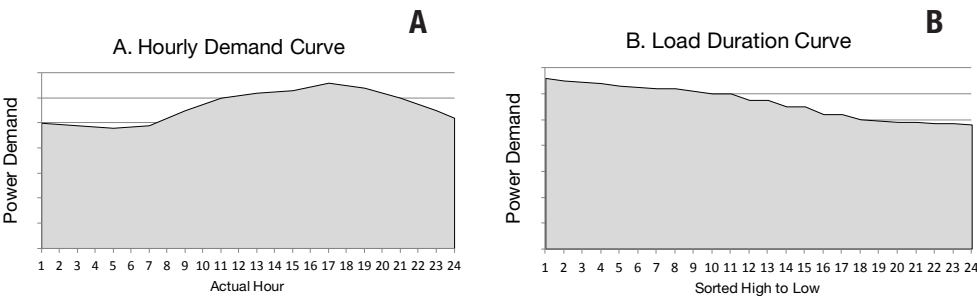


Figure 1.1. A typical demand curve profile (A). The raw chronological data by actual hour is sorted from high to low to create the Load Duration Curve (B).

With aggressive penetration of renewable energy, which has accelerated rapidly in the last decade, it is questionable whether the traditional LDC simplification is still valid. To address this potential problem, new software packages, such as Plexos[™] are available that use what is called Chronological modeling (Nweke et al. 2012).

Table 1.1. Types of Capacity Expansion Models

Capacity Expansion Model	Solves for
Load Duration Curve (LDC)	Capacity to meet energy (GWh) needs
Chronological (Chrono)	i) Capacity to meet energy (GWh) needs that also has ii) Capabilities to meet system challenges posed by renewable energy, such as net load ramping

The goals of this work are to

1. Illustrate the value of Chrono modeling relative to LDC methods (Figure 1.2A).
2. Quantify the value of additional portfolio flexibility using Chrono modeling (Figure 1.2B).

For goal 1 we test the LDC and Chrono models on a target utility with aggressive wind and solar penetration and a reliance on natural gas for capacity expansion. For this exercise we assume gas turbines in simple and combined cycle are the basis of new-build decisions (BASE new build capacity pool) in addition to the renewable expansion.

For goal 2 we use Chrono modeling for the same utility, and compare outcomes using the base capacity pool with outcomes using an alternate flex capacity pool instead. The Flex capacity pool includes all of the gas turbine options in the base, as well as additional technologies with improved dynamic capabilities, i.e. more flexible. By “more flexible” we mean faster starting, faster ramping, lower minimum loads and with greater modularity. The goal is to quantify if Chrono modeling installs greater flexibility (at lower costs) and if so, to explore the mechanisms and quantity by which flexibility brings value.

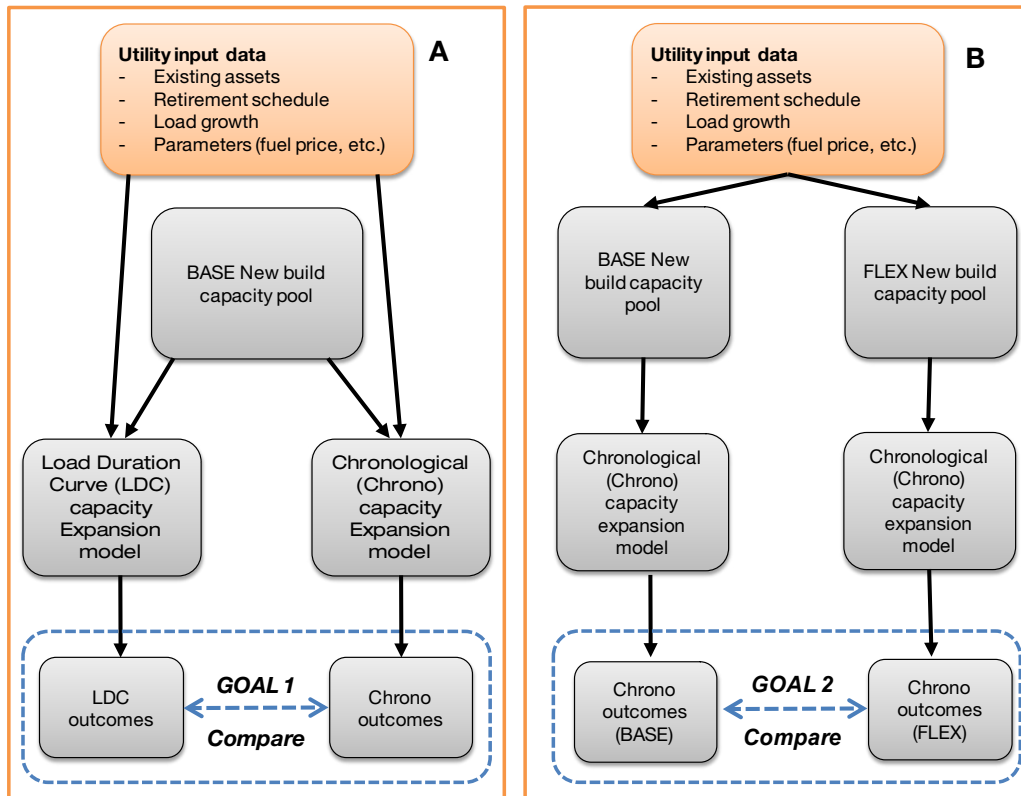


Figure 1.2. Illustration of the two major comparisons performed in this work.

2. CAPACITY EXPANSION MODELING, PAST AND PRESENT

Capacity Expansion Models (CEMs) are complex software packages that mathematically determine the optimal, minimum cost buildout of new generation capacity (and in some cases transmission). These programs are necessary because the best solution may not always be obvious. New generation assets are not generally islanded, or isolated – they operate in concert with numerous power stations and in concert with transmission lines from neighboring utilities across which energy is bought and sold. Therefore a CEM solves for assets that minimize the cost of capital and operations for the entire fleet. Cost minimization in this context can mean, for example, recognizing that it may be lower cost to purchase additional energy than it would be to invest in a new power plant and self-generate.

Because CEMs are tasked with solving for time horizons of 10, 20 or more years, they are computationally intensive. Until recently, limitations in computing power constrained the size of the problems that could be solved. Certain simplifications and assumptions were made to simplify the problem and make it more tractable.

Load Duration Curve (LDC): One common simplification is the adoption of the load duration curve (LDC). Loads change throughout the day and seasonally. Historically these load patterns were not dramatically variable, and it was sufficient to approximate them with a mathematical simplification (LDC) which provides all of the information related to the energy needs for the system, while discarding the time dependent nature (chronology) of the load.

The time dependent load for simulation (10, 20+ years) is then “decomposed” into representative blocks (e.g., weekly) across the time horizon and represented within the model with its LDC counterpart. The CEM then solves for the least cost investments (in time) required to meet the energy needs represented by the LDC.

The LDC approach is the basis for most commercially available CEMs. They have been historically successful in maintaining reliable power systems precisely because the assumption of replacing the time dependent, chronological load with an LDC approximation was valid. This was valid because, for the most part, load did not vary substantially hour to hour.

Challenges of renewable integration: Today, however, it cannot be safely assumed that load will behave in such a monotonic fashion (smooth transitions hour to hour). This is true in particular for systems experiencing accelerating growth of renewable energy sources (RES, e.g. wind, solar). Renewable energy sources add complexity to the problem in four ways.

1. Many states/nations have Renewable Portfolio Standards (RPS) that mandate that by a certain date a specific proportion of annual system energy consumed must come from RES.
2. RES are only capable of generating energy when the potential energy they rely on is available – wind turbines only generate when wind is blowing, solar panels only generate when the sun is shining.
3. The potential energy they rely on is variable and not predictable with ultimate certainty. Wind and solar generators can have significant intra-hour variations in output, and although forecasting is able to estimate with some certainty what the output from these units will be, at least on an aggregate level, it is not 100% accurate.

4. The variable cost (fuel, operations & maintenance) is close to zero, meaning in market-driven contexts they are assured dispatch. And in some markets, it is legislated that their energy be used first (priority dispatch).

The first point indicates that investment in RES is not subject to traditional mechanisms used to ensure lowest cost delivery of energy. Points 2 and 3 imply that it is not possible to truly schedule and/or dispatch RES in the traditional manner. The last point, low variable cost / priority dispatch, means that the load will first be served by whatever RES energy is available, and the remainder served by truly dispatchable resources (thermal, nuclear, hydro, demand response, storage).

The concept of net load: Items 2, 3, 4 in the list above give rise to the concept of the net load. *Load* is the true demand that must be served moment by moment. Load is first served by renewable energy, and the remainder is called *net load* – the load that dispatchable resources must serve – it is at times equal to, but often less than the true load, and it is more variable than the normal load. For systems experiencing aggressive penetration of RES, the difference between load and net load can appear as in Figure 2.1.

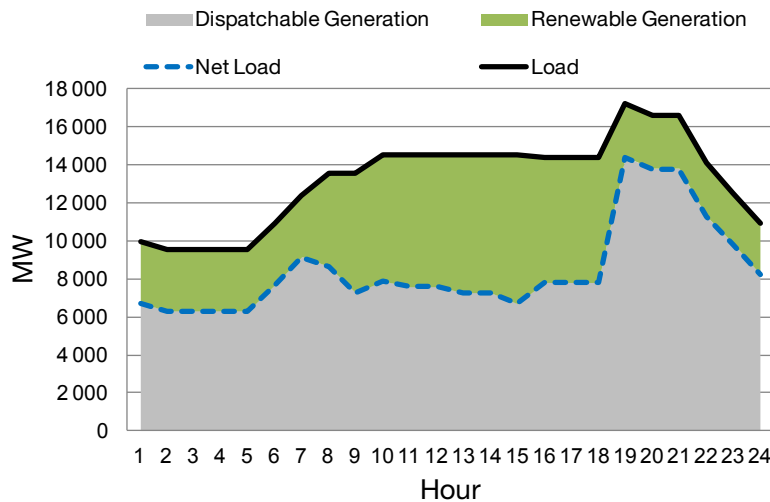


Figure 2.1. Illustration of load versus net load for a shoulder month day for a California utility in the year 2022, when the state of California is required to comply with a Renewable Portfolio Standard of 33%.

It is fairly well recognized (e.g. ISO-NE 2010; Lew et al. 2013) that as systems integrate greater amounts of RES such as wind and solar, the following will occur primarily for thermal assets (coal and gas-fired power stations)

- Capacity factors will be reduced, they will run fewer hours and generate less energy serving net load.
- Renewable energy with variable costs approaching zero will drive market prices down, so dispatchable resources will not only run fewer hours, they will be paid less for each MWh they generate.
- Number of starts/stops will increase, adding cost to generation

- Cycling and ramping will increase to balance variability in net load.
- Amount of time spent in a part-loaded state and at reduced efficiency will increase (so units can have available ramp capacity to attend to net load fluctuations).

Given this situation, capacity expansion models will often assume a renewable buildout to meet legislated RPS goals and then solve for the least cost buildout of dispatchable resources.

This is where the concerns arise regarding traditional Load Duration Curve approaches. The LDC method does not recognize net load chronology and therefore cannot account for the impacts of a variable net load. These impacts include cycling, part load operation, ramping and starts/stops, all of which impose additional costs, but are not accounted for within the LDC framework. Historically these issues have been addressed outside of the CEM framework, but can they be taken into account already at this fundamental stage?

Chronological modeling: There is at least one alternative to the LDC methodology and it is called Chronological Modeling (Chrono). With Chrono, the optimization algorithms use the raw net load profile instead of decomposing it into a load duration curve. The Chrono method retains all of the information on energy needs of the system in addition to the ramping needs of a variable net load profile.

At present, the only commercially available software that includes both LDC and Chrono approaches for capacity expansion simulations is PLEXOS™. Therefore, using PLEXOS™, we can test the accuracy of the LDC method through comparison with more advanced approaches, such as Chrono, for a system with variable net load.

3. COMPARING THE NEW AND THE OLD

In this section we define the approach used to compare the “New” (Chronological Modeling) versus the “Old” (Load Duration Curve) types of capacity expansion simulations. First, let’s start with the data users have to supply common to both approaches. Input data includes the time period, or horizon. In our case we use 10 years, but it can be set to 20, 30 or more years. For markets where renewable generation is mandated by RPS legislation, we must define renewable buildout (to meet RPS goals) and renewable generation by hour. For all existing assets (thermal plants, wind/solar farms, etc.), information on their size (installed capacity, MW), performance and, if applicable, retirement dates for any assets that are scheduled to go out of service. In addition, projected fuel prices, carbon costs if applicable and any other projections (such as load forecasts) must be defined. Finally, a pool of units and technology types for new build capacity, including details such as build cost (\$/kW), efficiency, unit size, etc. is required as input to the model.

The capacity expansion model then employs complex iterative optimization algorithms to determine the least cost solution. Least cost here is defined as the minimum Net Present Value (NPV) of all capital (Capex) and operating (Opex) costs across the 10 year horizon¹.

End effects: The NPV also includes end effects. Because assets have economic and technical lifespans, the investment decisions decided in years 1 – 10 will have impacts beyond the last year of the horizon. To account for these “end effects” it is often assumed that when the assets reach the end of their life, they will be replaced in kind at similar costs. The magnitude of the end effect can be quite large and is dependent entirely on the Capex and Opex values in year 10 (Note, we are using a 10 year horizon for illustrative purposes, the same discussion applies to any horizon length, e.g. 20, 30 years).

¹ An integrated resource plan will typically run a capacity expansion model multiple times across sensitivities in pricing/forecasts, calculate statistical risk/reliability metrics, and generate curves of price (\$) vs. risk (e.g. the “Efficient Frontier” plot). In this work, we focus solely on the capacity expansion modeling process (LDC vs. Chrono) and flexibility evaluations, as they are underlying processes for the full integrated resource planning effort.

Table 3.1. Capacity Expansion Models determine the types of new generation assets to install, and the associated annualized Capex. New generation is added to the fleet as capacity and then operational costs for the fleet are calculated. Raw values are noted with a subscript noting the year. Final values for each year are then discounted, noted with a subscript noting year as well as the letter “d”. Discounted values are used to calculate Net Present Value of Capex + Opex for the solution.

Year	Raw values		Discounted values	
	Capex	Opex	Capex	Opex
1	Capex ₁	Opex ₁	Capex _{1D}	Opex _{1D}
2	Capex ₂	Opex ₂	Capex _{2D}	Opex _{2D}
3	Capex ₃	Opex ₃	Capex _{3D}	Opex _{3D}
4	Capex ₄	Opex ₄	Capex _{4D}	Opex _{4D}
5	Capex ₅	Opex ₅	Capex _{5D}	Opex _{5D}
6	Capex ₆	Opex ₆	Capex _{6D}	Opex _{6D}
7	Capex ₇	Opex ₇	Capex _{7D}	Opex _{7D}
8	Capex ₈	Opex ₈	Capex _{8D}	Opex _{8D}
9	Capex ₉	Opex ₉	Capex _{9D}	Opex _{9D}
10	Capex ₁₀	Opex ₁₀	Capex _{10D}	Opex _{10D}

Discounted annual values are then used in the Net Present Value (NPV) calculation below.

$$\text{NPV} = \{ \text{Capex}_{1d} + \text{Opex}_{1d} \} + \text{End Effect} \quad \text{Eq. 1}$$

$$\text{End Effect} = \frac{\text{Capex}_{10d}}{\text{Discount Rate}} + \frac{\text{Opex}_{10d}}{\text{Discount Rate}} \quad \text{Eq. 2}$$

As can be seen from Eq. 2, the end effect is entirely dependent on the last year values for Capex and Opex. As we shall see, the end effect can be quite large, 50% or more of the total NPV. Therefore one gage of the “accuracy” of a capacity expansion model is the extent to which the operational cost used in the CEM is reflective of the true operational costs.

Use of short-term dispatch modeling to validate the capacity expansion model: How do we know the true operational cost? One estimate of true operational cost is to take the fleet suggested by the CEM for year 10 (last year of horizon) and put it into a detailed dispatch model for load and renewable profiles expected for year 10. Dispatch models differ from capacity expansion models, in that dispatch models are relied on to answer questions on operational costs and unit commitment, typically for much shorter time periods (a month, a year) than capacity expansion model horizons (10, 20+ years). Accordingly dispatch models take more details into account and are generally considered more accurate estimators of operational costs than those obtained from long term capacity expansion models. For example, the LDC method does not retain information on cycling and is therefore unable to account for start costs, whereas a dispatch model retains all of the chronology and explicitly accounts for all start and cycling costs.

To determine which of the two methods is most accurate, we perform capacity expansion modeling on a target utility using both methods (LDC and Chrono) with a common set of inputs, including the types of units considered for new build capacity. Then we compare the operational costs of the fleet buildout in both cases against more accurate estimates obtained using detailed dispatch modeling for the last year of the horizon and calculate and compare error terms (Figure 3.1). The error terms (Eq. 3) are the basis of the comparison for goal 1 (Figure 1.1A).

The error term is calculated as:

$$\text{Error term} = 1 - \frac{\text{True Opex (from detailed dispatch model for year 10)}}{\text{Opex for year 10 as calculated by the Capacity Expansion Model}} \quad \text{Eq. 3}$$

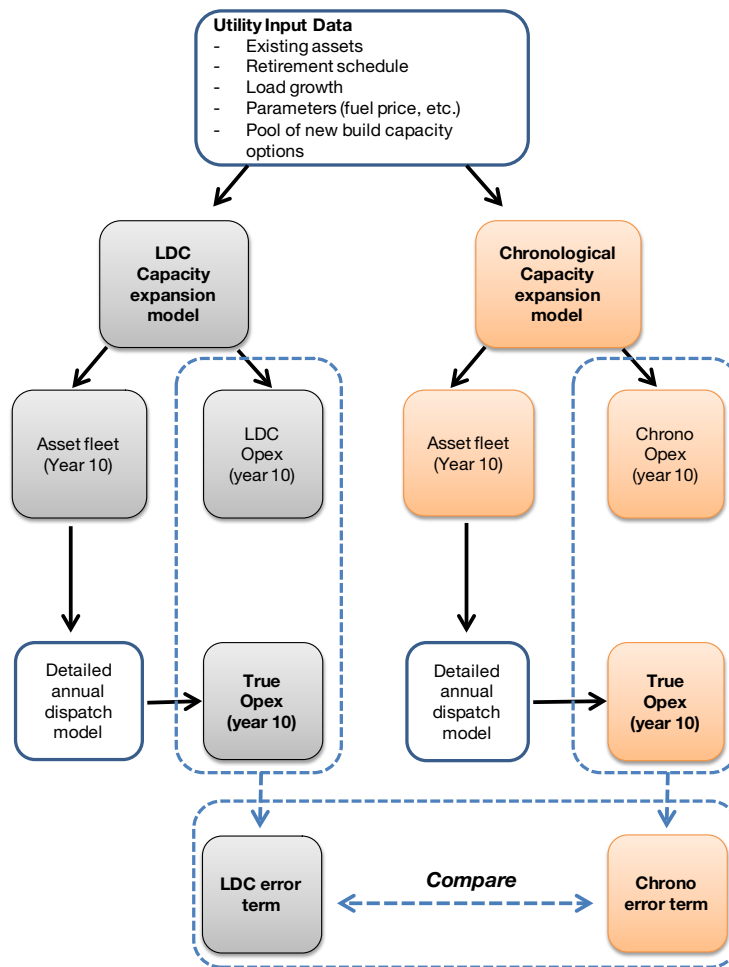


Figure 3.1. Flow diagram of comparison approach between Load Duration Curve (LDC) and Chronological (Chrono) capacity expansion models. Model inputs (top block) are representative. Error terms gage the accuracy of the capacity expansion model.

Additional details on model set up:

- Both models (LDC & Chrono) were run using the “LTPlan” module in PLEXOS™
- For both LDC and Chrono modeling in LTPlan, each year was broken into days with 24 (hourly) time blocks. This is a much higher temporal resolution than typically considered (e.g. year broken into weeks with seven daily time blocks).
- For each day the LDC method assigned a load duration curve approximation to the net load, and the Chronological approach used the true net load, retaining the chronology, across the 24 hourly blocks.

- Hourly dispatch modeling was performed on the fleet suggested by each (LDC & Chrono) for the last year of the horizon using the “ST Schedule” module in PLEXOS™
- Each simulation was performed using Mixed Integer Programming, which implies that capacity can only be installed in increments of unit sizes. So, for example, if 50 and 100 MW gas turbines are among the options and the capacity need is for 75 MW, the program must choose two 50 MW units or one 100 MW unit.
- The maximum amount of new-build combined cycle assets was limited to 55% of new build capacity, which matches historical buildouts of utilities in the proximity of the target utility (described below).
- A capacity reserve margin of 15.1% was imposed; for each year of the horizon, the firm capacity installed had to be 15.1% higher than the peak load for that year. This is in line with a typical NERC (National Electric Reliability Council) recommended reserve margin of 15%.
- Capacity reserve margins were assessed relative to “firm capacities”, defined in the following chapter.

The target utility is described in Chapter 4. The types of units considered as common input for the comparison of LDC vs. Chronological modeling are discussed in Chapter 5.

4. DEFINING THE UTILITY

We chose an Investor Owned Utility (IOU) indicative of a large western US utility that is experiencing modest load growth, an aggressive renewable buildout based on legislated Renewable Portfolio Standards, low gas prices, and retirement of aging boiler plants, similar in size and facing challenges utilities face in and around the California market. To define this utility, we leaned on the 2012 California Public Utility Commission (CPUC) / California Independent System Operator (CAISO) Long Term Planning and Procurement (LTPP) database. This database is a modified form of the 2012 Western Electricity Coordinating Council (WECC) model. The 2012 LTPP database is a large database/PLEXOS™ model used by researchers, government agencies and consultants (e.g. CAISO 2013; Kema 2013; Lew et al. 2013; E3 2014a) to evaluate renewable integration and information on capacity expansion planning into the future (specifically the 2012 model provides information for the year 2022). This model includes detailed information on every power plant in the entire western United States, including size (MW), efficiency (full and part load), minimum loads, minimum run and down times, ramp rates, etc. as well as information on the utility to which it belongs or is associated with.

This information allowed us to “extract” the assets of an investor owned utility from the database to use as the basis of this study. The intent of this study is to use the utility as a basis for evaluation of the questions posed in this work, not to create a suggested course of action for a specific utility. Therefore the “target utility”, or “the utility” used here, even though based on real world data, is only a proxy for the case analysis.

The utility has an installed capacity in the 1st year of the evaluation of approximately 26 GW. Load growth and peak demand growth are approximately 1.2% per year. Approximately 6 GW of retirements occur across the 10 year horizon, with the majority (@ 5 GW) occurring in the year 2021. Renewables are in the range of 7 GW in 2013, increasing to 11.5 GW by 2022 (40% wind, 60% solar). In addition, the utility has over 9 GW of transmission capacity connecting it to neighboring utilities. Details on the capacity, retirement schedule, etc. are included in Appendix 1. Details on how transmission was modeled are in Appendix 2. An example of net load challenges the utility will face in 2022 is shown in Figure 2.1, which shows a 6 GW net load ramp across 1 hour.

5. NEW BUILD CAPACITY OPTIONS FOR COMPARISON OF LDC AND CHRONO CAPACITY EXPANSION MODELS

For this work we have decided to evaluate new, natural gas fired capacity options only. While other options exist they may not be viable as new builds (e.g. new coal, nuclear or reservoir hydro), and/or may not be economically/technologically “mature” (e.g. energy storage), making them less likely to contribute greatly to the capacity needs of large-scale systems in the near term.

New-build options consisted of gas turbine options commonly considered in integrated resource planning (Table 5.1): two aeroderivative gas turbines (50 MW & 100 MW class), one frame/industrial gas turbine (200 MW class), and two combined cycle options (300 and 600 MW classes). Performance information was obtained from the GTPRO™ software, V23.0. Owners cost (indicative) follows recommendations by WECC (E3 2014b) and include EPC cost plus additional development costs such as land, interconnection, permitting, etc. Full details on the information used for these options in the modeling process are included in Appendix 3.

Table 5.1 New build gas turbine options for the comparison of LDC and Chronological modeling approaches. “Net” means performance at the high side of the step-up transformer and inclusive of all parasitic losses. Owners cost are indicative but the rankings generally hold across markets.

Gas turbine configuration	Net capacity (MW)	Net efficiency (% LHV)	Owners cost (\$/kW)
50 MW Aero	49	40	1200
106 MW Aero	105	42	1100
208 MW Frame GT	208	38	800
300 MW 1x1 GTCC	303	55	1250
600 MW 2x1 GTCC	611	56	1150

The new build gas turbine capacity options (Table 5.1) were used as input to the capacity expansion models (LDC and Chronological) for the utility described in the previous chapter.

6. COMPARISON OF OUTCOMES FROM CHRONOLOGICAL VS. LDC CAPACITY EXPANSION MODELS

Capacity buildout and NPV costs from both methods: Due to retirement of steam turbine assets later in the horizon and a modest peak load growth, no new builds were proposed by either modeling approach until the year 2019. The Chrono method proposed installation of greater amounts of capacity (Figure 6.1, table 6.1) and also indicated higher NPV costs (10 year horizon plus end effects) than proposed by the LDC method (Table 6.2).

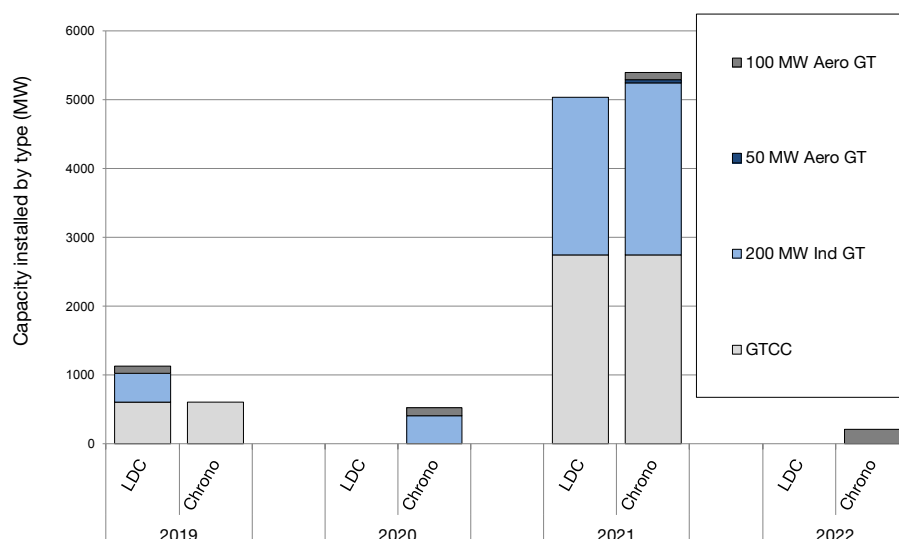


Figure 6.1. Capacity installed by type, year and method (LDC vs. Chrono)

Table 6.1 Capacity installed by type, LDC and Chrono models

MW Installed	LDC	Chrono	Difference
GTCC	3358	3358	-
GT Ind	2704	2912	208
GT Aero (50MW)	-	49	49
GT Aero (100 MW)	105	420	315
Total MW installed	6167	6739	572

Table 6.2 NPV values for each method.

NPV (BUSD)	LDC	Chrono	Difference
Opex	48.4	49.6	1.2
Capex	4.1	4.4	0.4
NPV total cost from LT plan	52.5	54.0	1.5

The LDC approach is solving a simplified representation of a variable net load profile that results from substantial amounts of renewable energy. The Chronological method recognizes net load ramping challenges and installs a greater amount of capacity of a different mix that results in a higher cost than the portfolio proposed by the LDC method. The question remains which one is truly more accurate?

Influence of end effect: Recall that the NPV calculation is composed of the sum of 10 year NPV values for Capex and Opex (Eq. 1), with the addition of end effects (Eq. 2). The composition of elements for each of the NPV values indicated Opex accounted for more than 90% of the total NPV, and Opex end effect accounted for 50% of the total NPV.

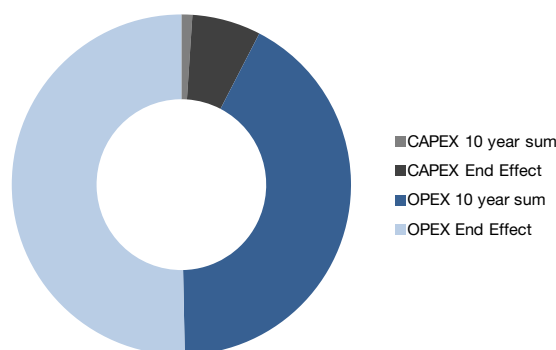


Figure 6.2 Individual components of total NPV value. Values were equivalent (with marginal differences) for both LDC and Chrono methods.

Since Opex is the major influence on final NPV values, it is necessary to evaluate how accurate the Opex values are. Instead of evaluating Opex for every year subject to different capacities based on retirements and resource additions, a value for the year which has the most influence on NPV, namely the 10th year Opex was analyzed. This is the final year of the horizon in which all retirements have occurred and all new capacities are built, and it is the single value which most influences the magnitude of Opex end effect.

In order to evaluate Opex for the last year, we took the final fleet buildouts (from LDC and Chrono model results) and used them as input to an hourly dispatch model in PLEXOS™. Hourly dispatch models include far more detail than considered in operational cost calculations of capacity expansion models, including the Chrono method. Therefore, one measure of the accuracy of a capacity expansion model is the degree to which the resulting Opex values align with Opex values determined from a dispatch model.

Error terms from Eq. 3 (Table 6.3) indicate the 10th year Opex in the LDC method underestimated true operational costs by 7% compared to 3% for the Chrono method. Errors for both methods imply that the capacity expansion model will underestimate the total NPV. These errors are inescapable, an artifact of the underlying assumptions in the capacity expansion models. However, if different models are available, the one with the smallest error terms should be chosen. This is especially relevant in long term planning results that base end effects on Opex values from the last year of the horizon.

These results support the concept that the Chronological method is a better approach for systems with heavy renewable penetration and variable net loads. Because the Chrono method retains information on time development of net loading, it installs capacity that has the requisite capabilities to meet net load ramps, as evidenced by the smaller error terms for the Chrono method. Because the magnitude of the error is smaller with the Chrono method, the overall NPV values (dominated by Opex) can also be considered to be more robust and realistic relative to LDC approaches. In other words, the LDC method underestimates the capacity and capability needed and ultimately underestimates the operational costs of the utility portfolio. If this would be the sole determinant of the portfolio planning, the utility would not select the optimal portfolio mix and the cost of energy to the ratepayer would not be based on the optimal solution.

Table 6.3 Comparison of Opex from dispatch simulation results and from capacity expansion models for the year 2022.

Dispatch model results (BUSD)	LDC	Chrono
Fuel + VOM + CO ₂ + start costs	2.77	2.74
Import (cost)	0.08	0.08
Export (revenue)	0.74	0.73
Total dispatch model opex	3.58	3.55
Opex from capacity expansion model	3.34	3.45
Error term (Eq. 3), %	7	3

7. CAPACITY OPTIONS – HOW TO VALUE INCREASED DIVERSITY AND FLEXIBILITY

Now that we have determined that the Chrono method is most appropriate for systems with a variable net load influenced by renewable energy sources, we can move to the next question. Given that these systems require assets that can best handle low net loads and large net load ramps, how would a more diverse and capable fleet of resources influence costs? Specifically, if the traditional pool of gas turbine based choices for capacity expansion were expanded to include additional generation types, how would the outcome (fleet buildout, NPV) of a Chronological capacity expansion model differ?

Alternate flexible options for gas fired capacity: To test the questions posed above, we considered additional options (Table 7.1) based on natural gas-fired, internal combustion engines (hereafter referred to as ICE). Full details on the information used for these options in the modeling process are included in Appendix 3.

Features of modern (specifically medium-speed, 500-800 rpm) internal combustion engines include:

- Modular (10 to 20 MW per unit) capacity for projects up to 500 MW or more
- Highest simple cycle efficiency (46–48% depending on engine model).
- Very high part-load efficiency
- Insensitive to temperature: no derate on output/efficiency until $> 100^{\circ}\text{F}/38^{\circ}\text{C}$
- Insensitive to altitude: no derate on output/efficiency until $> 5000\text{ ft}/1500\text{ m}$
- Minimum stable loads of 30% (per engine), as low as 1% of plant load for a large multi-engine facility
- Operational ramp rates of 100% per minute or more (from min stable to full load in $< 1\text{ min}$)
- Fast start (0 to full load) in $< 5\text{ minutes}$, MW to grid in 30s
- High reliability and availability
- No minimum run time
- Minimum down times of 5 minutes
- Unrestricted number of starts/stops per day with no impact on cost or maintenance
- Automatic Generation Control (AGC), remote dispatch and black start capability
- No process water consumption due to usage of closed loop radiator cooling
- Proven technology, power plant applications worldwide, with decades of experience. Wärtsilä, the leading supplier, has over 55 GW of power plant references, 2.7 GW in the USA.

Table 7.1 New build internal combustion engine options. “Net” means performance at the high side of the step-up transformer and inclusive of all parasitic losses. Owners cost are indicative but the rankings generally hold across markets.

Internal combustion engine configuration	Plant net capacity (MW)	Net efficiency (% LHV)	Owners cost (\$/kW)
10 MW class units	50+	44%	1150
20 MW class units	100+	45%	1100

Base and Flex capacity pools: A comparison is then made between Chrono capacity expansion modeling outcomes using the Base and Flex alternative pools of new-build capacity options. From the previous comparison (LDC vs. Chrono) the results for the Base pool are the same as the results for the Chrono method in the previous section. Therefore, for this comparison, the only additional simulation needed is to run the same Chrono capacity expansion model, only this time using the Flex capacity pool. Note that the Flex pool includes all of the gas turbine based options in the Base, with the primary difference being the inclusion of two internal combustion engine alternatives.

For this second part of the study, the utility was analyzed using the Chrono capacity expansion model, under two scenarios; BASE and FLEX. The BASE scenario uses the Base capacity pool, and the FLEX scenario uses the Flex capacity pool. Final NPV values and operational aspects of the suggested fleets from the scenario outcomes are compared (Figure 7.1).

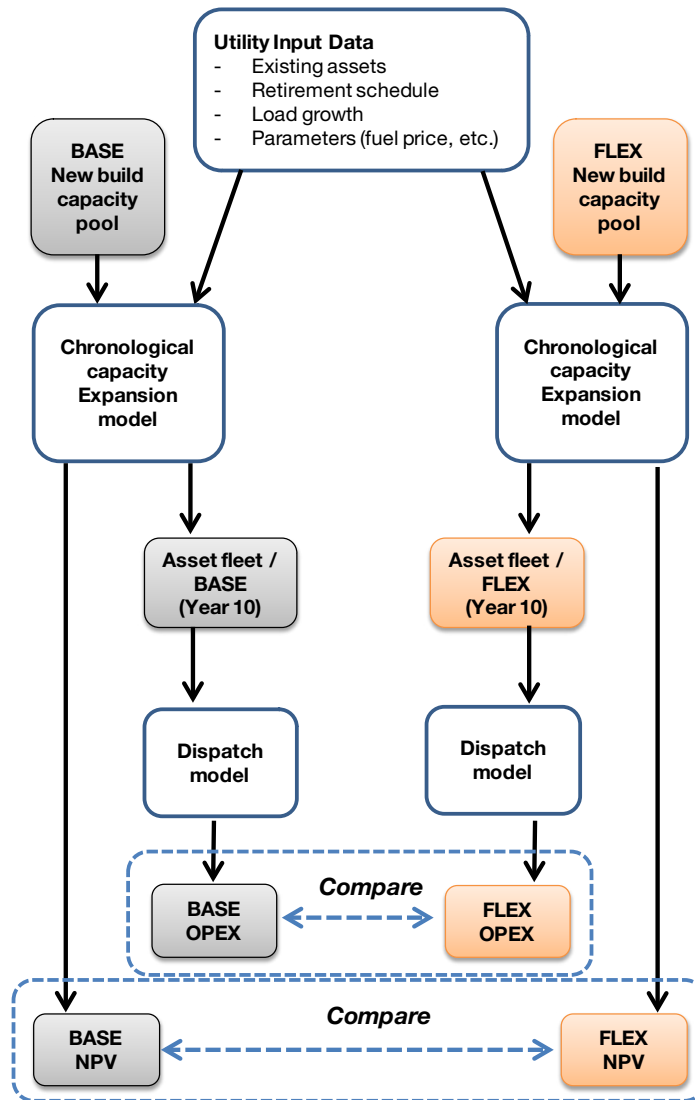


Figure 7.1 Comparison of outcomes from Chronological capacity expansion model using two different new build capacity pools. The BASE scenario is based on gas turbine units only (Base capacity pool). The FLEX scenario uses all units considered in the Base capacity pool plus two additional combustion engine units.

Outcomes of Chronological Capacity Expansion Modeling with Base and Flex capacity pools :

1. The timing of investments is altered (Figure 7.2).

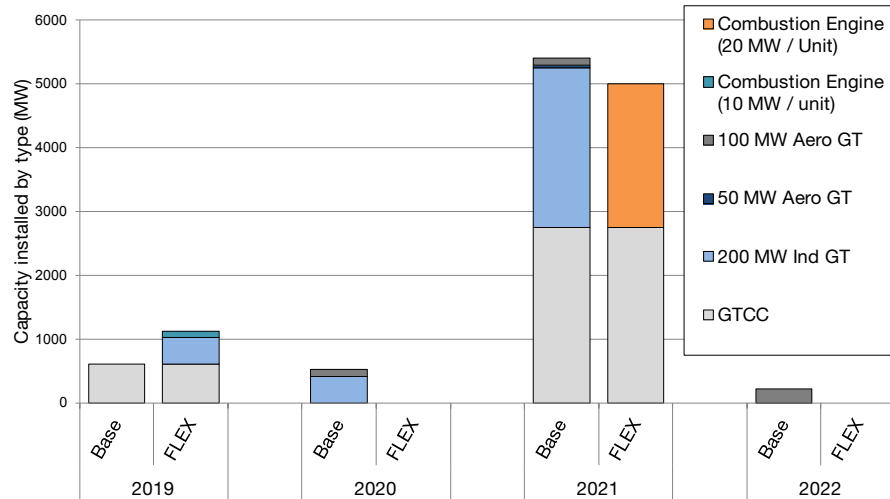


Figure 7.2 Differences in resource selection, Chrono method, Base versus Flex capacity pools.

2. When modular, flexible capacity are part of the pool of new build options (FLEX), 628 MW (9.3%) less new capacity is needed to meet utility load obligations (Table 7.2).

Table 7.2 Capacity installed using Chronological capacity expansion modeling using Base and Flex capacity pools.

MW Installed	BASE	FLEX	Difference
GTCC	3358	3358	-
GT Ind	2912	416	- 2496
GT Aero (50 MW)	49	-	- 49
GT Aero (100 MW)	420	-	- 420
Combustion Engine (10 MW)		92	92
Combustion Engine (20 MW)	-	2245	2245
Total MW installed	6739	6111	- 628

3. The FLEX scenario yielded a NPV of 865.8 MUSD less than the Base (Table 7.3)

Table 7.3 FLEX scenario yielded a NPV of 865.8 MUSD (in 10 years) less than the Base scenario

NPV values (\$ BUSD)	BASE	FLEX	Delta
Operation cost	53.54	52.96	- 0.58
Capital cost	4.67	4.68	0.02
Export (revenue)	- 3.94	- 4.30	- 0.36
NPV total cost	54.28	53.41	- 0.87

4. Flexible, modular ICEs supplant aeroderivative (469 MW) and industrial (2,496 MW) gas turbines (Table 7.2). This is due to a combination of modularity, superior efficiency and more dynamic capability (more ramp capacity).

Overall, the ICE units have higher capital cost than frame GTs they displace, equivalent cost with aeroderivative GTs they displace and have higher efficiency and ramp rates than either. Therefore the CAPEX portion of NPV is marginally higher for the FLEX scenario, while operational costs and export revenue are dramatically improved (Table 7.3). The reasons behind the improved operational performance are beyond the simple efficiency advantage of ICEs over GTs and are more related to optimization of fleet dispatch (including GTCCs). To fully explore the fleet level optimization, we evaluated dispatch simulations for the last year of the horizon.

Outcomes of annual detailed dispatch modeling: The capacity fleets from the Base and Flex scenarios were used as input against chronological net load development for the last year of the horizon (year 10, or 2022), in a detailed hourly dispatch model.

1. The operational costs of the Flex scenario with a large buildout of combustion engines yielded savings of 64 MUSD/year (Table 7.4). These results imply that the added Capex costs for the FLEX scenario would be paid for with 1 year of operational savings (payback < 1 year). This was calculated as follows: The total cost of all new build capacity was calculated as the sum of unit output (kW) times build cost (\$/kW) for the fleets from the BASE and FLEX scenarios. The BASE and FLEX scenario fleet costs were 6.74 BUSD and 6.8 BUSD respectively (undiscounted). Thus the FLEX scenario fleet has a 60 MUSD Capex premium, which is less than the (undiscounted) 64 MUSD annual Opex savings from year 10 for the FLEX scenario.

Table 7.4 Annual cost accounting from dispatch simulation, year 2022, for Base and Flex scenario fleet buildouts.

Annual Cost (\$ BUSD)	Base	Flex
Fuel + VOM + CO2	2.673	2.751
Start Costs	0.076	0.048
Import (Cost)	1.105	1.003
Export (Revenue)	-0.300	-0.314
Total	3.553	3.489
Savings with Flex Scenario		0.064

- In the FLEX scenario, the utilization of efficient combined cycle assets improved. Existing GTCC capacity factors increased, while the same for existing GTs and new Industrial GTs decreased. This implies greater system efficiency as combined cycles run more at higher efficiency, and less efficient units run less. For comparison, ICEs in the FLEX scenario had a capacity factor of 18% (vs. 9% for industrial GTs in the BASE scenario).

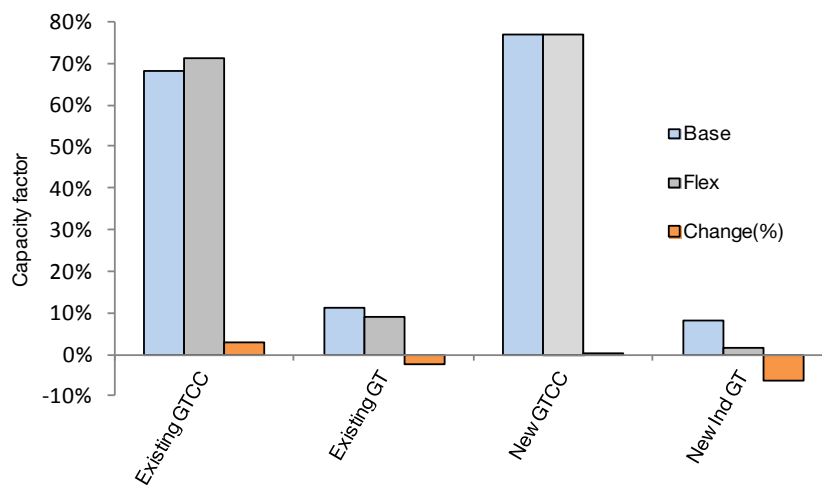


Figure 7.3 Differences in resource selection, Chrono method, Base versus Flex capacity pools

- In the Flex scenario, the number of starts for gas-turbine based capacity was reduced (Figure 7.4). Start costs in the FLEX scenario were reduced (Table 7.4) as a consequence of a reduction in the number of starts per unit. Each unit start for industrial GTs and GTCCs is assigned a start cost. For example, 200 MW class new industrial GTs are assigned a \$10,000 per start cost, justified by their frequent starts and less than 2 run hours/start.

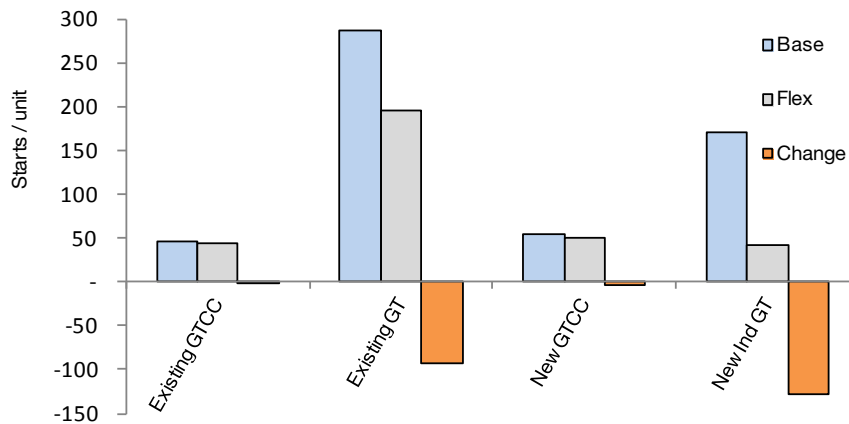


Figure 7.4 The number of starts/unit for Base and Flex scenarios. “Change” is the value from Flex minus the value from the Base scenario.

4. In the Flex scenario, the amount of imports was reduced, and the revenue from exports increased. Increased system efficiency coupled with lower start costs yielded a reduced marginal cost of the portfolio for the FLEX scenario, reducing import costs and increasing export revenue (Table 7.4).

The value of flexibility – where do the savings come from: The results of this analysis show that if efficient and flexible capacity is considered in capacity expansion planning above and beyond the traditional gas turbine based capacity, portfolio outcomes will be superior. In this case the flexible alternative evaluated were combustion engines (ICEs). Superior outcomes with ICEs include

- Reduced NPV (including end effects), savings of 866 MUSD
- Reduced amount of installed capacity, 628 MW less
- Increased fleet efficiency, which
 - Reduces marginal costs
 - Reduces costs of purchased energy (imports)
 - Increases revenue from export energy
- Dispatch (last year) results show annual operational savings of 64 MUSD/year
- Dispatch results also show a 1.5% reduction in CO₂ (for the fleet)

The savings and improvements can be separated into a few broad areas;

1. **Portfolio optimization:** By injecting more flexible capability with zero (maintenance-based) start costs combined cycle assets can generate at a more stable dispatch that optimizes the fleet generation cost. This may seem counter-intuitive, where it would be easy to assume higher efficiency CE units would decrease the capacity factors of all other units, but this is not the case. Capacity factors of the most efficient units increased while starts decreased. This indirect enhancement is what we term Portfolio optimization.

2. **Efficiency improvements:** Portfolio optimization is manifested by a combination of reduced cycling and increased system efficiency, yielding a reduced marginal cost for the entire portfolio.
3. **Improved import/export net balance:** The lower marginal cost of the portfolio reduced imports from neighboring providers and increased exports and resulted in the positive portfolio effect.
4. **More capital efficient buildout:** The smaller increments of the ICE based assets can reduce overbuild situations as they can be tailored to the exact requirements while maintaining economies of scale, e.g. plants can be built for 160 MW or 180 MW with the same cost per kW installed.
5. **Less capacity needed:** Generally the greater the flexibility of a capacity type, the less capacity needed to meet net load fluctuations (Makarov et al., 2008). In addition, modularity allows for exact matching of capacity needs.
6. **CO₂ reduction:** Dispatch results show that the FLEX fleet generates more GWh, but consumes less fuel than the BASE fleet, reflected by a 1.5% reduction in CO₂ emissions. So the portfolio optimization and efficiency improvements show that increased flexibility also reduces the carbon footprint.

8. SUMMARY AND MOVING FORWARD

The first goal of this work was to illustrate the value of Chrono modeling over traditional LDC approaches. Comparison of operational costs from Chrono and LDC against a more detailed dispatch model showed that the error terms of the Chrono model were less than half of the LDC method. The reason for the difference is that the LDC approach cannot account for variability in net loading, which can have serious impacts on the dispatchable fleet.

These findings suggest utility resource planners should consider Chrono modeling as an alternative or complement to more traditional methods. If Chrono modeling is infeasible, due to cost and time required to transition from legacy use of LDC to Chrono and/or lack of computing power, detailed dispatch analyses across several scenarios should be used to judge (or modify) NPV outcomes of LDC simulations. The findings have increasing relevance for regions experiencing aggressive renewable penetration coupled with increasing net load variability. As the proportion of renewable energy increases, continued reliance on LDC methods may seriously compromise the validity of financial decisions related to asset acquisition and portfolio costs.

The second goal of this work was to explore how the Chrono method would value greater flexibility. The comparison was made between capacity expansion modeling results using a gas-turbine-centric Base pool of new-build capacity versus the same but including two additional internal combustion engine (ICE) alternatives, which have similar capital costs to gas turbines but are inherently more flexible (modular, fast start, fast ramp, fast shut down etc.). When ICEs were included as an option for the model to select, they supplanted over 2 GW of new build gas turbines, required 628 MW less capacity and yielded a net present value (NPV) savings of 866 MUSD. Although capital costs were higher, dispatch analysis showed the 64 MUSD/year savings in operational costs compared to the additional capital cost of 60 MUSD (non NPV) delivered a payback of less than 1 year.

While this work uses ICEs as a proxy for “more flexible capacity”, the approach illustrated would be equally applicable to any type of capacity including energy storage, distributed generation and demand response. Regardless of the type of capacity considered, this work shows additional flexibility with a minimum premium on capital cost (\$/kW) can yield significant fleet-level optimization, reduce fuel use, reduce CO₂ generation, reduce marginal costs, increase revenues from exports, and yield significant savings across the entire portfolio.

The engine of change – flexibility: Dispatch modeling of the FLEX scenario was used to show the source of savings on an annual basis related to combined cycle dispatch optimization, start costs, CO₂, import/export, etc. These operational savings were relative to the same system evaluated only allowing for gas turbines as new capacity (BASE scenario). Thus the savings were the result of the efficiency, modularity and flexibility of ICEs over GTs.

The value of flexibility that internal combustion engines provide has been explored in some detail in recent operational studies. In particular, Kema (2013), Wärtsilä & Redpoint (2013) and Wärtsilä and Energy Exemplar (2014) have performed dispatch simulations of the United Kingdom and the California Independent System Operator (CAISO) power systems in future years when renewable sources are expected to supply 30% or more of the energy needs. In all 3 studies, when combustion engines were introduced to the resource mix, significant operational savings were achieved (4–12% annually).

The mechanisms that contributed to the operational/system savings were the same as evidenced in this work for the FLEX scenario; optimization of GTCC dispatch, reduction of number of starts, increase in system efficiency, and reduction of CO₂ generation and costs. These prior system studies did not include the impact of capital costs, instead they compared outcomes with different portfolios that included internal combustion engines as part of the capacity mix against a baseline scenario of planned gas turbine-based capacity additions. The assumption was that all gas-fired assets are somewhat similar in capital costs so the savings quantified are true operational savings based on two separate resource plans with similar capital costs. This current work is aimed at also including the capital cost issue directly in the evaluation, while also looking at the optimization from the utility portfolio planning point of view, similar to what many utilities perform in their Integrated Resource Planning.

Ancillary services: Ancillary services (operational reserves or contingency reserves) are reserve capacity intended to, among other things, make up any shortfalls. Shortfalls can be caused by a mismatch between scheduled and actual real time operations. For example, between hourly and 5 minute, and between 5 minute and real time markets. These shortfalls are caused by discrepancies between scheduled and actual generation and are exacerbated with greater amounts of renewable energy (e.g. as wind generation has higher variability and uncertainty than thermal generation, the inclusion of wind will increase both these metrics of a portfolio and increase the need for regulation, a primary service for adjustment between 5 minute forecasts and real time). The most expensive ancillary services are “uplift” services, those that require units to run at part load and be available to ramp upwards as needed or as a result of a contingency (e.g. the largest unit in the system trips). The previous operational studies illustrated that when combustion engines make up 6 – 8% of system capacity, they can provide up to 80% of uplift ancillary services at significantly lower costs. This, in turn, frees combined cycles from having to provide these services and allows them to run at their maximum full load efficiency with a minimum number of starts and stops. Based on these prior studies, it is reasonable to expect that fleet buildouts that include superior flexibility will also optimize provision of ancillary services and provide even greater savings than indicated here, which were based solely on energy. Further analysis could include ancillary service requirements in addition to capacity and energy considerations.

The value of modularity: Because internal combustion engines can be installed in capacity blocks of 10 or 20 MW, capacity can be installed to meet projected needs, avoiding the “lumpy investment” issue. Capacity blocks of 10 and 20 MW allow for meeting projected needs without overinvesting. Modularity also provides another advantage from a system benefit perspective. A multi-unit plant can follow loads by cycling units on and off, with no additional start or maintenance costs. In this manner, the majority of units on line are at or near full load, at maximum efficiency and with subsequent minimization of fuel costs and CO₂ generation.

Finally, in many areas the cost of new transmission is prohibitive, and congestion on lines can drive up marginal costs significantly. Modular plants allow for custom-sized plants in load pockets that could offset transmission costs for new lines or upgrades and/or alleviate transmission constraints and congestion costs.

Putting it in the context of a full Integrated Resource Plan: Given chronological modeling should complement or replace traditional capacity expansion models, resource planners should take advantage of all commercially viable potential candidates for new builds during their evaluations. This requires moving beyond the traditional mix of gas turbines in simple and combined cycle. This work highlights one such candidate, internal combustion engines and demonstrates the substantial savings that could be achieved mainly through fleet optimization effects. However, full integrated resource plans (IRPs) also have to consider other factors such as reliability and sensitivity to risks (such as deviance in hydrology, weather, fuel or load forecasts).

Smaller sized generating units will result in greater reliability (Biewald & Bernow 1988). Multi-unit ICE plants are based on increments of 10 or 20 MW, smaller than typical GT unit sizes. Low forced outage rates also increase reliability, and these rates for ICEs are in the range of 1% per unit, less than that for most gas turbines on a per-unit basis. As an example, a 10 x 20MW ICE plant would have a forced outage rate (for all 200 MW) of 1% to the 10th power. Compared to a 200 MW industrial GT the forced outage rate of the 200 MW ICE plant is literally orders of magnitude lower. Small incremental unit sizes and low forced outage rates for utility scale ICE plants will increase system reliability and consequently, decrease the reserve margin necessary to meet reliability standards.

In terms of sensitivities, simple logic would show that if fuel price increased, preference would be given to the most efficient simple cycle units (ICEs). If renewable energy became more volatile, preference in the simple cycle space would be given to units with the highest ramp rates (ICEs) and highest part load efficiency (ICEs).

Utilities must also work towards legislative goals, such as minimization of greenhouse gases (such as CO₂). This work and several earlier (operational) studies all show that enhanced flexibility increases system efficiency and reduces CO₂ emissions (and costs). Thus the greater the modularity and flexibility of the fleet, the more able it is to assist in meeting legislative goals and the less sensitive it is to variances in forecasts.

This work demonstrates the value of Chronological capacity expansion planning and shows the value of increased flexibility in resource selection (using Internal Combustion Engines as a proxy for “a more flexible resource”). We hope that this work will stimulate further thought and investigation across the industry, with a goal towards delivering reliable, sustainable and cost-effective energy via investment in the right amounts of capacity with the right capabilities to handle the challenges of renewable integration.

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APPENDIX 1 INFORMATION ON THE UTILITY USED FOR THIS STUDY

Existing capacity: The first year of the horizon for analysis was 2013. In the year 2013, the utility had approximately 26,200 MW of installed capacity (Figure A1.1). All parameters for the individual plants making up this capacity were taken from the WECC model (e.g., capacity, efficiency, ramp rates, minimum up/down times, start times, etc.)

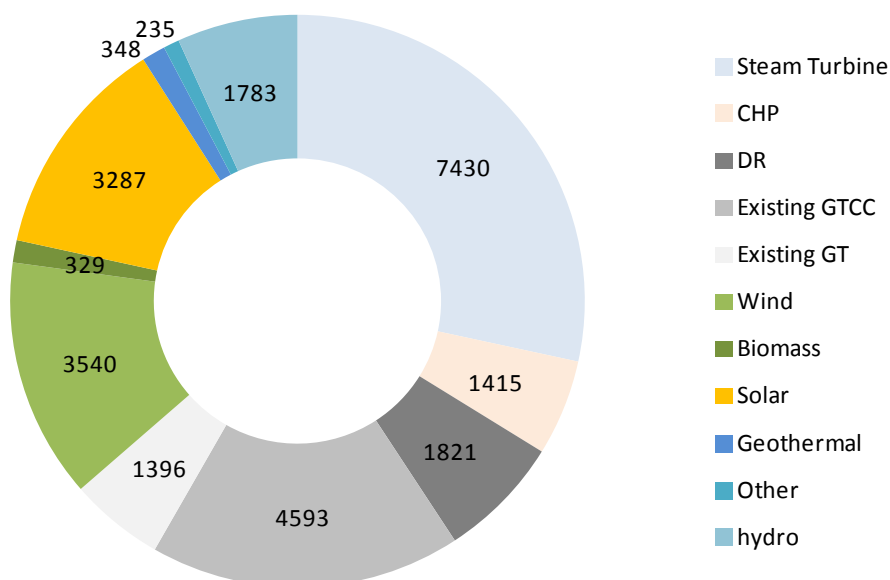


Figure A1.1. Installed Capacity (26.2 GW) for the year 2013. Abbreviations; Gas Turbine (GT), GT Combined Cycle (GTCC), Demand Response (DR), Combined Heat and Power (CHP).

Transmission capacity: In addition, the utility has transmission lines with approximately 9 GW of capacity, allowing for substantial purchase/sale of energy (MWh) as warranted. In order to account for pricing across the interties, the interties were treated as a price station (see Appendix 2).

Peak load and energy demand growth: These resources serve a peak load (2013) of approximately 23.5 GW. Future peak load growth and energy demand are modest, approximately 1.2% per year for each (Figure A1.2).

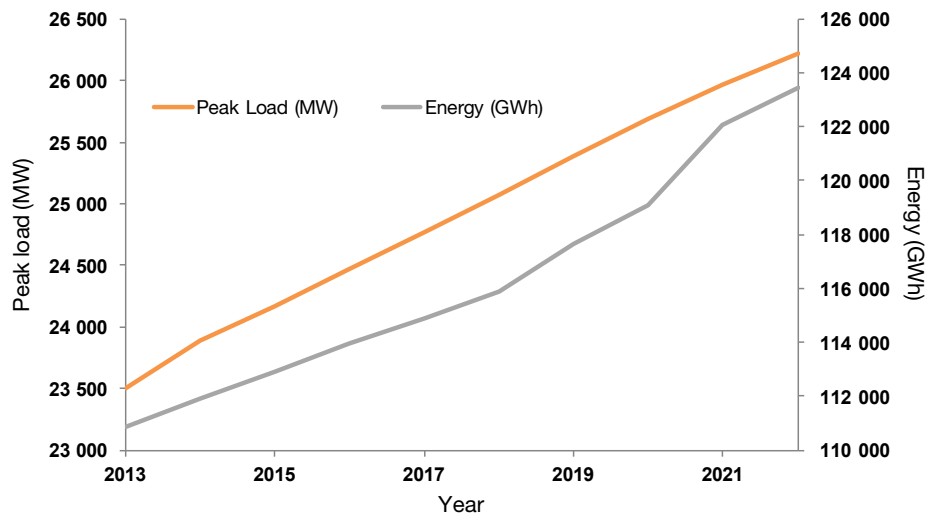


Figure A1.2 Assumed peak load (MW) and energy (GWh) growth 2013 – 2022.

Retirement schedule of existing assets: While existing assets are capable of meeting load at present, challenges are posed by retirement of existing steam, or boiler plants (Figure A1.3). In this specific case, the units are gas-fired and are facing closure due to legislation that bans the use of once-through cooling (e.g. the use of river or coastal waters for heat rejection). They could just as easily be coal-fired boilers facing closure due to economic viability concerns related to low-cost shale gas coupled with compliance costs associated with environmental legislation.

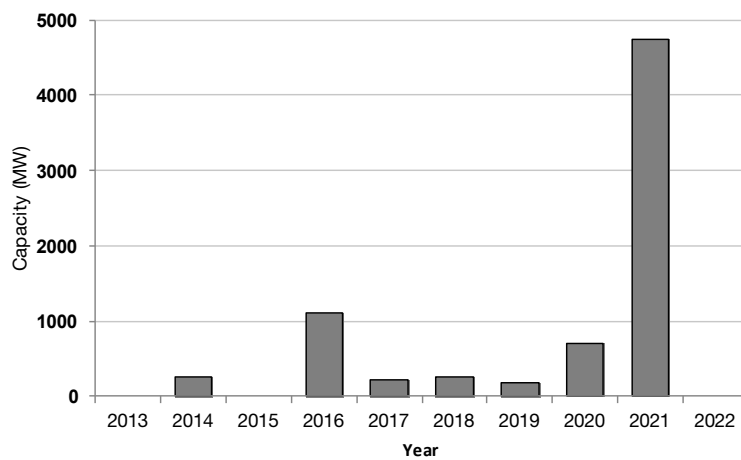


Figure A1.3 Steam turbine power plant retirement schedule 2013 – 2022.

Scheduled buildout of Renewable Energy Sources (RES) for compliance with Renewable Portfolio Standard (RPS) requirements: The buildout of RES capacity was assumed (Figure A1.4), and considered a) dependent on compliance with RPS legislation and b) independent of economic evaluation or consideration within the context of capacity expansion modeling. The buildout of RES will supply approximately 30% of energy (GWh) for the utility by the year 2020.

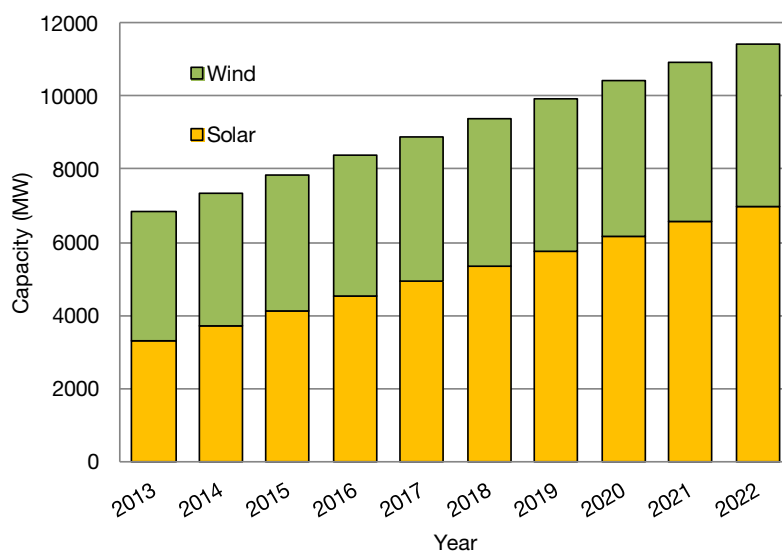


Figure A1.4 Scheduled buildout of Renewable Energy Sources (2013-2022).

Firm capacity: While units are commonly defined by their name plate capacity, for the purpose of capacity reserve margins it is necessary to define what is called firm capacity. Here “firm capacity” refers to the availability for the capacity to deliver energy during the hour of annual peak load. If, for example, the peak load occurs at night, the firm capacity of solar is zero.

Table A1.1 Firm capacity ratios for selected technologies

Technology type	Firm capacity rating
Thermal	100% of summer rating
Hydro	82%
Biogas	62%
Wind	0.2%
Solar	40–70%, depending on load shape at peak hours
Transmission / Interchange	100%

APPENDIX 2 TRANSMISSION PRICING

The utility chosen for this work had several transmission lines with an aggregate capacity of approximately 9.5 GW, with the potential to supply a substantial portion of the energy needs. Energy flow into the utility across these lines were considered as costs, while flows outwards were considered sources of revenue. This section describes the basic methodology of how the transmission line pricing was established to inform import/export decisions in the capacity expansion and dispatch simulations.

Recall the data for the utility was taken as a subset of the original Plexos™ 2022 WECC model. The WECC model is a dispatch simulation tool used to evaluate generation within, and energy transfer among, multiple entities (utilities, states, balancing areas) in the broad geographic region which the WECC model encompasses. Within the state of California, each of the major utilities is designated as its own region, with basic transmission represented among them and with other entities (within CAISO, such as large municipalities that manage their own load, or with transmission across state lines).

Therefore, the WECC model can be used as a template for understanding how the utility trades energy across transmission lines. The process by which this was done is described as follows:

1. Run an hourly dispatch simulation for the entire WECC system for the year 2022, using all defined assets within the 2022 WECC model.
2. Acquire the hourly regional power price for the utility and the neighboring areas from that run.
3. Define regional market heat rates for the utility and neighboring areas as the regional power price divided by the fuel (natural gas) price.
4. For each major transmission line capable of importing or exporting energy, within the PLEXOS™ capacity expansion model define a pair of proxy generators, one for import and one for export.
5. Use hourly market heat rate profiles derived in step 3 as the input heat rate for the two proxy generators.
 - The export is modeled as a negative generator in PLEXOS.
 - In this way, the import and export generators are placed in the supply stack along with other internal resources and PLEXOS will determine whether it is economic to dispatch internal resources or use the import generators.
 - PLEXOS will decide when it is economic to use cheaper internal resources to sell the power to the neighbors at a higher price.
6. Because these price stations are only sensitive to the price signal. It is necessary to place a ramp rate to these import/export generators. Otherwise they can move their generation output up and down instantaneously, which is not realistic.
 - Historical flow data was evaluated for the maximum observed ramp rates (MW/h, from hour to hour) across transmission lines connecting the utility to neighboring areas.

- Regression analysis showed that the maximum observed ramp rate across any line was no more than 1/3 of capacity.
 - Therefore a ramp rate limitation was imposed on the generators/price stations, so that the power flow was limited to 1/3 of line capacity hour to hour.
7. The ramp limitations are only applicable to Chronological capacity expansion simulations. In the LDC mode simulation, the chronological constraints are ignored, as is the ramp rate limitation.
 8. Imports for any hour were assigned a cost of the MWh purchased times the regional price defined for the hour.
 9. Exports for any hour were assigned revenue as the MWh exported times the higher regional price in the neighboring region. Costs (fuel, VOM, CO₂, start costs) to supply energy for export are accounted for in Opex separately.

While this method of using price stations to account for import and export of energy is dynamic, it is still based on an assumption that the overall import and export pattern around the utility will not change significantly from year to year.

APPENDIX 3 PARAMETERS FOR GAS-FIRED GENERATION USED IN SIMULATIONS

Parameter	Units	100 MW Aero GT	50 MW Aero GT	200 MW Industrial GT	300 MW 1x1 GTCC	600 MW 2x1 GTCC	50+ MW ICE	100+ MW ICE
Max Capacity	MW	104.9	49.37	208	303	611	9.2 ⁽¹⁾	18.4 ⁽¹⁾
Min Stable Level	MW	31.47	14.811	52	90.9	183.3	2.76 ⁽¹⁾	5.52 ⁽¹⁾
Load point(50% load, avg temp) ⁽²⁾	MW	52.45	24.7	104	151	611	4.6 ⁽¹⁾	9.2 ⁽¹⁾
Load point (100% load, average temp) ⁽²⁾	MW	104.9	49.37	208	303	305	9.2 ⁽¹⁾	18.4 ⁽¹⁾
Heat rate (50% load, avg temp) ⁽²⁾	BTU/ kWh	10,700	11,412	13,381	8033	7964	9470	9363
Heat rate (100% load, avg temp) ⁽²⁾	BTU/ kWh	8913	9356	10,005	6852	6805	8550	8400
Load point(50% load, summer temp) ⁽³⁾	MW	47.9	22.85	97.5	141	284	4.6 ⁽¹⁾	9.2 ⁽¹⁾
Load point (100% load, summer temp) ⁽³⁾	MW	95.8	45.7	195	282	568	9.2 ⁽¹⁾	18.4 ⁽¹⁾
Heat rate (50% load, summer temp) ⁽³⁾	BTU/ kWh	11,071	11,628	13,695	8351	8255	9470	9363
Heat rate (100% load, summer temp) ⁽³⁾	BTU/ kWh	9083	9498	10,150	7010	6960	8550	8400
VO&M charge	\$/MWh	4	3	2	2	2	3.5	3.5
FO&M charge	\$/kW/ year	7	7	5	13	11	7	7
Firm capacity	MW	104.9	49.37	208	303	611	9.2 ⁽¹⁾	18.4 ⁽¹⁾
Maintenance rate	%	2	2	3	3	3	1	1.4
Forced outage Rate	%	2	2	3	3	3	0.7	1
Mean time to repair	hrs	24	24	24	24	24	7	7
Build cost	\$/kW	1100	1200	800	1250	1150	1150	1100
Build time	Months	12	12	12	24	24	12	12

Parameter	Units	100 MW Aero GT	50 MW Aero GT	200 MW Industrial GT	300 MW 1x1 GTCC	600 MW 2x1 GTCC	50+ MW ICE	100+ MW ICE
Technical life	years	25	25	25	25	25	25	25
WACC	%	7	7	7	7	7	7	7
Economic life	years	25	25	25	25	25	25	25
Min build set	# units	1	1	1	1	1	5	5
Start cost (\$/start)	\$	0	0	10,000	20,000	35,000	0	0
Start time (min)	min	10	10	15	90	90	5	5
Min up-time	Hours	1	1	1	8	8	0.033 ⁴	0.033 ⁴
Min down-time	Hours	1	1	1	4	4	0.083	0.083
Cooling type (comment)		Dry/Rad	NA	NA	ACC	ACC	Radiator	Radiator
NOTES & COMMENTS								
GTPRO ID#		441	374	435	435	435	471	470
Gas pressure needed (psia)		926	693	400	400	400	102	102
Compressor included (CAPEX/ Performance)		No	No	No	No	No	No	No
Max ramp-up assumption	(%/min)	50	40	20	20	20	70	70
¹⁾ Combustion engine performance is PER ENGINE								
²⁾ Average temperature = 20°C								
³⁾ Summer temperature = 30°C								
⁴⁾ Value used for simulation purposes only (In reality there is no minimum up-time for ICEs)								



INCORPORATING FLEXIBILITY IN UTILITY RESOURCE PLANNING

Wärtsilä Power Plants is a leading global supplier of flexible baseload power plants of up to 600 MW operating on various gaseous and liquid fuels. Our portfolio includes unique solutions for peaking, reserve and load-following power generation, as well as for balancing renewable energy. Wärtsilä Power Plants also provides LNG terminals and distribution systems. As of 2014, Wärtsilä has 56 GW of installed power plant capacity in 169 countries around the world.

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