A SIMULATION MODEL FOR THE LONG-TERM ANALYSIS OF DECENTRALIZED ELECTRICITY MARKETS

by

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To the memory of my mother...

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ABSTRACT

A SIMULATION MODEL FOR THE LONG-TERM ANALYSIS OF DECENTRALIZED ELECTRICITY MARKETS

After the liberalization of the electricity generation industry, capacity expansion decisions are made by multiple self-oriented power companies. Unlike the regulated environment, decision-making of market participants is now guided by price signal feedbacks and by an imperfect foresight of the future market conditions that they will face. In such an environment, decision makers need to understand long-term dynamics of the supply and demand sides of the power market. To visualize the competitive electricity power market dynamics, a simulation model based on system dynamics (SD) philosophy is developed in this study. The developed model includes the demand module, the capacity expansion module, the power generation sector, an accounting and financial module, various competitors and a bidding mechanism.

During the modeling process, various submodels have been developed and tested before being integrated to form a complete system model. At each phase of modeling, besides international literature, expert opinions have been considered in determining the model structure, relationship between entities, parameters and equations used in the model, to ensure the representativeness and the reliability of the model. In this context, additionally an Analythical Hierarchical Process based sub modeling and analysis has been conducted, in order to better understand and treat power generation facility options available to investors.

The SD model has a flexible structure for parametric studies, such that results of different strategies/policies can be analyzed. The results obtained from the scenario analysis reveal that the model is able to capture most of the long and short-term dynamics which occur both on the supply and on the demand sides of the power market. The developed model is an excellent tool to be used in understanding, investigating and experimenting on a decentralized electricity market, especially in regard to investor behaviour; supply, demand and price fluctuations, short and long term effects of various decisions and primary energy resource limitations.

ÖZET

SERBESTLEŞTİRİLEN ELEKTRİK PİYASASININ UZUN DÖNEMLİ ANALİZİ İÇİN BİR BENZETİM MODELİ

Elektrik üretiminin serbestleştirilmesiyle, yatırım kararı bağımsız firmalar tarafından alınmaktadır. Serbest piyasada, düzenlenen piyasanın tersine, piyasadaki oyuncuların kararları; markette oluşan elektrik fiyatından ve oyuncuların gelecekte markette karşılaşabilecekleri belirsizliklerden etkilenmektedir. Bahsi geçen piyasa şartlarında, karar vericiler elektrik tedariğinde ve talebinde oluşan uzun dönemli dinamikleri anlamaya ihtiyaç duymaktadırlar. Bu çalışmada, rekabetçi elektrik piyasasının dinamiklerini anlamak için Sistem Dinamiği (SD) metodolojisi kullanılarak bir benzetim modeli geliştirilmiştir. Geliştirilen model; talep modülünden, yatırım modulunden, elektrik üretimi modülünden, muhasebe ve finans modülünden, çeşitli rakiplerden ve ihale sisteminden oluşmaktadır.

Modelleme süresince, çeşitli alt modeller geliştirilip test edildikten sonra birbirlerine entegre edilerek SD modeli oluşturulmuştur. Modellemenin her aşamasında; modelin yapısı, modüller ve değişkenler arası ilişkiler, modelde kullanılan denklem ve parametreler, modelin gerçeği yansıtma yeteneğini ve güvenilirliğini sağlamak amacıyla uluslararası yayınların yanısıra, uzman görüşleri de dikkate alınarak belirlenmiştir. Bu çerçevede, yatırımcılara sunulan santral alternatiflerini daha iyi anlayabilmek ve tespit edebilmek için Analitik Hiyerarşi Prosesine dayalı bir alt model geliştirilmiştir ve analiz edilmiştir.

Geliştirilen SD modeli parametrik çalışmalar için esnek bir yapıya sahiptir; öyle ki farklı stratejiler/politikalar analiz edilebilmektedir. Senaryo analizleri boyunca elde edilen sonuçlar, elektrik piyasasında gerek elektrik tedariği, gerekse elektrik talebi tarafında oluşan uzun ve kısa dönemli dinamiklerin model tarafından yakalandığını göstermektedir. Geliştirilen model, serbestleştirilen elektrik piyasasını anlamak, incelemek ve bu ortamda deneyim kazanmak için mükemmel bir araçtır.

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1. INTRODUCTION

This thesis is about management, planning and decision making in a decentralized energy sector. What is meant by energy sector decentralization is briefly explained below. How this study supports management, planning and decision making in this environment is then explained and discussed in problem formulation, model development, model solution and scenario analysis states.

There exist three rather distinct components in the electricity market. These components are generation, transmission and distribution. First of all, electricity is generated via burning fossil fuels (such as hard coal, lignite, natural gas etc.), harnessing wind, hydro, solar energy, or nuclear fission. Then, electricity is sent through high-voltage, high-capacity transmission lines to the local regions, where it is consumed. When the electricity arrives in the region in which it is to be consumed, it is transformed to a lower voltage and sent through local distribution networks to end-use consumers.

In the traditional electricity markets, all three of the above mentioned vertically related sectors have typically been tied together within a utility (in short it is said to be vertically integrated) which has been either investor-owned and state-regulated, or owned by the local municipality (in Turkey, these three components were vertically integrated and owned by the state up to 1993). All over the world, these three sectors were thought as natural monopoly for a long time. In the transmission and distribution sectors, having separate power line networks for each company, in order to facilitate effective competition, would obviously be inefficient. On the other hand, if power lines owned by different companies were allowed to interconnect to form a single network, the laws of physics demonstrate that there would be significant externalities: the flow on one line affects the capacity of other lines in the system to carry power. Generation was argued to be a natural monopoly because of the large scale of efficient generation plants and the losses that occurred with long-distance transmission, which made it more efficient to have local areas served by one or a small number of large generating plants.

However, there has been a tendency of deregulation and liberalization of the electricity market all over the world since the 1990's (leading at the same time to de-monopolization and diversification). The factors stimulating deregulation of the electricity market all over the world are summarized in Section 2.1.

1.1. The Need for Different Policy Making Tools in Deregulated Electricity Markets

Before the liberalization of the electricity sector, investments in power plants used to be based on centralized (and presumably optimized) capacity expansion planning, at national or regional level. The aim of this planning was to determine the right level of generating capacity (over time), the optimal mix of generating technologies and the timing of investments and retirements of capacity, to ensure that future demand in a certain region would be served at minimum cost with an adequate level of reliability (Ku, 1995). In such an environment, the future demand and fuel prices are the only significant sources of uncertainty. Additionally, producers are not price takers, i.e., they have the opportunity to determine market price.

As mentioned in Section 1.3, after the liberalization of the electricity industry, electricity is no longer supplied by one monopolistic supplier. In the resulting competitive environment, combined forces of supply and demand conditions, rather than the historic costs of the underlying assets will determine electricity prices. In such an environment, as it is mentioned in detail in Section 1.3., future electricity prices are unpredictable; they can rise and fall in response to competitors' changing market powers and power plant portfolio, time variant imbalances in supply and demand, new regulatory rules (such as surcharges, subsidies, quota). Considering these arguments, we can say that investment decisions mainly depend on cash flow expectations of the investor and on the dynamics of demand and supply in the power market, while policies, constraints and availabilities (regarding incentives, surcharges, taxes, transmission needs, primary energy reserves, real time pricing issues, seasonal effects, current plant portfolios of the producers, interest rates on debt) greatly influence these primary factors.

In such an environment, the decision makers, that is individual power companies or a public regulating authority, try to answer the following questions;

- How much new capacity should a particular generating company build in order to meet growing demand and to increase or preserve its share in the market?
- At what level should generators price their products in the market, in order to balance market share, solvency, short term profitability and long term expectations?
- Whether withholding (deliberately reducing available electricity with the aim of increasing prices) is a profitable strategy or not?
- Which types of plants will be more attractive in a decentralized, competitive environment?
- How will different competitors react against certain behavioral trends?
- Under which conditions renewable power plants will be attractive for the power companies?
- How can a regulator ensure that competitive prices prevail in the market, whilst sufficient incentives for capacity expansions and new entries are maintained?

To answer questions such as the ones forwarded above, decision makers need to understand long-term dynamics of the supply and demand side of the power market, as investment decision depends on it. Besides, since deregulation is a revolutionary process that introduces new rules to the market, it renders history irrelevant. As a result, decision makers need a decision tool, which focuses on learning and understanding the system (instead of predicting the future based on the historical data) and offer sets of possible scenarios of future that can be studied to grasp additional insight.

1.2. What is Proposed in the Thesis?

1.2.1. A Decision Making Tool Based on System Dynamic Approach

A simulation model, mimicking the behavior of the competitive electricity power market, based on System Dynamics (SD) philosophy is proposed and developed in this study. Since, SD focuses on learning and understanding the system (instead of predicting the future), so does the developed model.

By means of such a tool, companies and regulators will have the opportunity to understand possible consequences of different decisions that they may make under different policies and market conditions. Moreover, such a tool is a risk-free way for the managers to gain experience in a competitive environment which they are not familiar with. Besides, the model is suitable to test up to 227,812,500,000,000 different scenarios, to be considered by decision makers in their short and long term planning.

From the start, representativeness, controllability, reliability, ease of use of the model to be developed have been regarded as key design and development issues, while data needs had to be seriously considered. Primary sources of data has been TEIAS (Turkish Electricity Transmission Company), EMO (Chamber of the Electrical Engineers), while expert opinion and international literature has been consulted and relied upon in the development of the many mathematical relationships and in the setting of many parameter values.

The model, whose development and capabilities are explained in Chapter 5, is called the LEMM (Liberalized Electricity Market Microworld[1]). Its explanatory powers on the electricity sector in investigated and discussed through a rigorous scenario analysis, which is discussed in Chapter 7. The functionality, effectiveness, practicality and educational capabilities of the model are also tested on different decisions made by 26 students at Sabanci University. These sets of activities are discussed in Chapter 8.

Accordingly, we believe that, while the design and development of the LEMM has been a valuable research experience associated with the analysis and modeling of decentralized, deregulated electricity markets, the resulting system (i.e.the LEMM) is an excellent tool to be used in understanding, investigating and experimenting on a decentralized electricity market, especially in regard to investor behavior, supply, demand and price fluctuations, short and long term effects of various decisions and resource limitations.

[1]A Microworld, often called a management flight simulator, has become the generic name for a class of "what-if" tools, involving user-friendly interface and providing different types of reports summarizing information on wide range of aspects, for strategic thinkers and planners.

1.2.2. A Multi-Criteria Decision Making Tool (An Analytical Hierarchy Process)

Every planning activity requires making choices among different alternatives. In the past the choice among alternative power plant types was based on only monetary aspects. On the other hand, nowadays, actors in the energy market have to consider not only quantitative aspects (such as economic and technical aspects), but also qualitative aspects (such as political, cultural, social and legal aspects), while deciding on their power plant portfolio. However, some of these (economic, technical and environmental aspects) aspects can be handled by numerical models, whereas other aspects can be analyzed only in a qualitative way, or subject to a subjective judgments. As explained in Chapter 3, multi-criteria decision making tools (such as AHP, Electre, Promethee) are able to "organize" and "synthesize" the large set of variables coming from several specific judgments (qualitative or quantitative), helping the "decision maker" to evaluate and proritize several alternatives. Due to this reason, an AHP model (incorporating technical characteristics, resource availability, socioeconomic, environmental, cost, political and legal aspects) is developed for evaluating and prioritizing power plant types.

This model is used to make comparison between different power plant alternatives in Turkey. The power plant alternatives considered in the study are solar, nuclear, wind, hard coal, lignite, natural gas, fuel-oil and hydro-power. The developed AHP model has been based on opinions of experts representing different aspects of the energy market in Turkey (experts and managers from energy related regulatory bodies, financial institutions, environmental groups, non governmental organizations, generation, transmission and distribution companies).

By means of the developed model, expert opinions have been tapped to provide valuable insight into power plant types considered in the LEMM (by the passive investors, which are driven by the computer, through pre-set decision rules). In the LEMM, there are eight different power plant types and in a typical run (or game setting) all passive investors check the profitability and primary energy resources' reserve availibility of these eight power plant types and then make their investment choices regarding types and quantities. To study market behaviours in case investors consider less than eight power plant types as candidate investment alternatives, two additional options are offered to LEMM-users. In the first option, all passive investors invest only in the power plant types that ranked as the first five in the aggregated AHP results. In the second option, all passive investors invest in only the plant types that ranked as the first four in the AHP results.

1.3. Thesis Outline

The thesis is organized in eight chapters. The content of each chapter is briefly explained below.

Chapter 2-Overview of the Liberalized Electricity Market: This chapter presents the motivating factors for deregulation, the basic differences between regulated and deregulated markets.

Chapter 3-Literature Survey: This chapter contains literature surveys on multi-criteria decision making and on the implementation of SD in energy policy models.

Chapter 4-The AHP Model: This chapter presents the developed AHP model and the procedure implemented through the AHP study.

Chapter 5- System Dynamics Model of the Liberalized Electricity Market: This chapter introduces the main work in this thesis; a SD model of a liberalized electricity market. Model structure, basic underlying assumptions, data needs and compilation are discussed and explained in this chapter. Additionally, SD is briefly introduced in this chapter.

Chapter 6-Model Validation: This chapter introduces validation procedures implemented in SD. Additionally, extreme condition tests, behavioral sensitivity analysis conducted on the developed SD model and the data utilized in determining the relationships, equations and values of the parameters in the developed model are explained in this chapter.

Chapter 7-The Scenario Analyses: This chapter introduces the methodology implemented throughout the scenario analysis phase of the study and major findings obtained via scenario analyses. During the scenario analyses, effects of various factors, on the Electricity Market are analyzed. These factors can be categorized as investors' behavior characteristics, tax issues, price elasticity of electricity demand, capital structure of the investors, subsidies/surcharges, presence of long-term contracts in the market, regulatory issues, withholding and annual capacity addition limits on power plant types.

*Chapter 8-The Liberalized Electricity Market Microworld (LEMM)***:** This chapter introduces the effectiveness of the microworlds. Then the capabilities and limitations of the LEMM, interface of the LEMM, experimentations conducted with the LEMM are explained and the results obtained through these experimentations are discussed in this chapter.

*Chapter 9-Conclusions***:** This chapter presents a summary of the work done in this thesis and highlights the main findings.

2. OVERVIEW OF THE LIBERALIZED ELECTRICITY MARKET

2.1. Motives for Restructuring

Electric power system restructuring that has been going on throughout the world in the last 15 years has been stimulated by several forces. These factors can be categorized as technological, economic and other factors.

2.1.1. Technological Factors

Efficient Small Generating Units: As there was no efficient small scale generating units in previous years, generation part of the electricity market was considered to be a natural monopoly due to economies of scale. (Baumal, 1977) has shown that scale economies are sufficient to prove that monopoly is the "least costly form of productive organization". However, (Dewees, 2001) argues that the development of new generation technologies, such as the combined cycle gas turbine (CCGT), have greatly reduced the minimum efficient scale of a generating plant, thus bringing about the possibility of small independent generation units or even large electricity consumers installing their own generation plants.

In addition to the arguments presented in (Dewees, 2001), we can mention the following issues. Efficient small-scale generation technologies (such as the CCGT) allow small producers, (either new independent power producers (IPP) or large industrial consumers) to enter more easily into the generation market. In such an environment, possibility of many players generating at low cost brings about competition in the generation part of the electricity market.

However, to present a complete picture of the cost structure in the electricity sector, it is essential to mention the key issue of marginal cost of production. Initial investment cost and the marginal production cost represents the dominant economic factors in technology selection of the producers. However, based on the investment cost and marginal costs of present power plant types, it can be concluded that, in general the more expensive the production unit is (high investment cost); the cheaper it is to produce (low marginal costs). For instance, whereas hydro power plants and nuclear power plants have higher investment cost (compared to, for example, natural gas power plants), their marginal costs are distinctly lower than natural gas power plants' marginal costs. On the other hand, these differences between power plant types may lead to higher marginal costs, consequently higher electricity prices in the market, if new investments are only made in fossil fueled and gas units. This possible scenario would be due to investment decisions favoring lower investment cost generation units by multiple independent investors, in order to better control their financial risks. On the other hand, it is important to restate that entry and production in the electricity generation industry are economically more open owing to the new technologies.

New Metering and Information Technologies: (Pineau, 2000) states that real time information sharing and updating through the internet and high speed/capacity computing possibilities opened the way to new electricity transactions. For example, buying and selling electricity should be done one hour ahead to have efficient short term markets, but the physical scheduling and dispatch of the system needs to be done according to the settled transactions. Such critical tasks became possible only with the help of recent developments in computer hardware, software and networking.

(Dewees, 2001) also states that, the development of new metering technology and the advances in information technology infrastructure, to communicate prices and consumption data at low cost and high speed, has facilitated competition in metering and thus providing load-management services to consumers.

High voltage transmission lines: Technological developments in high voltage transmission lines have also stimulated deregulation of the electricity market. Owing to the developments of more efficient transmission lines, exchange of electricity over long distances became easier and more economic. As a consequence of this, social welfare (i.e. consumers' benefits and efficiency in the market) increases in two major ways. First, by taking advantage of non-coincidental peak loads, customers of different regions can have access to cheaper electricity at certain hours. Secondly, increased interconnections can reduce global capacity requirements, while keeping reliability at a similar level, because available capacity becomes accessible from different, far away regions.

The above three advances in technology; competitive smaller generation units, high voltage transmission lines and metering and information technology, seem to give a clear ground to transform electricity markets, from a regulated to a deregulated, decentralized, competitive market (Pineau, 2000).

2.1.2. Economic Factors

(Joskow, 1997) argues that the primary driver for restructuring has been the high prices charged by regulated utilities in the 1990's, as they recovered their cost of investments in expensive facilities, while reduced natural gas prices and increased efficiency of CCGT (Combined Cycle Gas Turbines) plants reduced the cost of new generation. Large customers rebelled at paying 6 or 7 cents per kilowatt-hour (kWh) to regulated utilities, when the marginal cost of wholesale electricity was 2.5 cents/kWh and long run marginal cost was 3-4 cents/kWh. The solution was to restructure the electricity market and to introduce the competition in generation.

On the other hand, competition is not only expected to lower prices to marginal cost, but should also result in a more efficient use of resources.

2.1.3. Other Factors

The below arguments are cited in (Pineau, 2000) as another group of factors motivating deregulation of the electricity market.

Price Diversity: In the traditional monopolistic electricity industry, some of the consumers complain about the "*price diversifications*" between different groups of customers (industrial, commercial, residential) and different geographic areas. Either the price level is regarded to be unfair because of c*ross subsidies* or some groups reacted to their inability to have access to the (lower) prices of neighboring markets. By the help of marginal cost pricing achieved through competition in the market, it is expected to end the price diversifications between various consumer groups, and to offer one price at a certain time, in all over the market (to each geographic region and consumer types).

Higher Efficiency of Private Companies: It is believed that "*private companies are more efficient than public ones*" (because of various financial, administrative, and managerial reasons). Based on this belief, it is argued that selling public assets in the electricity sector to private interests could be beneficial.

Unwise Investments: When there is no risk of loosing market shares or under utilizing available capacities, "*the producer has the possibility of investing in new capacities in an ineffective manner*". Because, if the consumers has no alternative suppliers, they have to pay as much as the producer wants, and this advantage of the producers allow them to recover all costs (i.e. consumer welfare reduces.) However, easy entry into the generation market and competitive prices result in more effective investments, or at least the responsibility of sound investment decisions is clearly felt by the investors. Consequently, the society does not pay for erroneous capacity additions through seller dictated higher tariffs.

Global Trends: In addition to the above factors, recent global trends also stimulated reforms in local markets. Accordingly, since there is a tendency to liberalize the electricity market all over the world, it becomes harder to justify and maintain regulation in any prominent and globally connected local market.

To sum up, all of the above factors more or less foster electricity market liberalization, but the most stimulating factor is technological developments in generating units and high-voltage transmission lines and falling fuel prices. Decreases in feasible operational scale of generating units and fuel prices have made it possible to economically generate with smaller units. Besides, technology improvements reduced the losses that occurred during transmission, making it easier for power plants hundreds of miles apart to compete with one another. It is economic to generate with smaller units and then integrating them into larger regional networks, which has increased the size of the market that could be served by individual generators. As a consequence, for many influential decision makers, those changes have been sufficient to conclude that electricity generation no longer requires any more government regulation than the regulation of markets for other commodities: such as gold, soybean, coffee etc. (Borenstein and Bushnell, 2000).

2.2. Extent of Restructuring of the Electricity Market

Electricity restructuring involves taking power away from monopolists and regulators and giving it to markets. Traditionally the planning of the electrical system and its operation have been the responsibility of regulated integrated utilities that generated, transmitted and distributed the electricity.

Restructuring starts with de-integration of generation, transmission and distribution. It involves, at a minimum, eliminating monopoly and allowing competition in generation, as well as requiring individual transmission network owners to transmit power from various generators to their customers. It may go further and establish a competitive wholesale power pool that sets an hourly (more or less) spot price. It may require integrated utilities to divest some of their assets, while maintaining some restrictions on potential buyers (owners of transmission and distribution networks, which remain natural monopolies, are excluded from engaging in competitive activities such as generation and retailing).

At the retail level, the distribution utility may hold a monopoly over the supply of electricity to customers in its service area, in which case it will purchase power on their behalf under contract and on the spot market, overseen by a regulator. (For instance, in Turkey there will be 22 distribution service areas.) Alternatively, retail competition may be formed, allowing competitive retailers to arrange price terms with customers, paying the distributor for delivering the power.

2.3. Features of Electricity As a Commodity

Electricity cannot be stored; it must be consumed as soon as it is generated. It can be transported long distances, but long distance transmission capacity is limited. These factors cause electricity markets to differ substantially from markets of many other commodities. Understanding the behavior of electricity markets requires some understanding of the shape of the electricity demand and supply functions, including the time variations of demand, of average and marginal cost pricing, of investment in generation capacity. Since retail competition is beyond the scope of this thesis, it is not further discussed.

2.3.1. Supply and Demand Elasticity

Electricity demand, or shortly load, is commonly divided into base, medium and peak load, as illustrated in the sample load-duration curve in Figure 2.1. Generation capacity can also be divided in a similar manner (base load, mid-merit, and peaker), as different types of plants are designed to serve different load segments. Base load plants have high capital cost and low operating cost (such as nuclear, storage hydro or coal-fired thermal plants). In general, they stay on line on a continuous basis (apart from maintenance and breakdown stoppages) meeting the base demand (i.e. the minimum demand level that exist throughout any 24 hour period). Mid-merit plants have moderate capital and operating costs (such as coal or oil-fired steam turbine plants, or combined cycle gas turbines (CCGT)). In general, they stay on line for most of the active hours of a typical day and, together with the base load plants, they meet average-above average demand levels. Peaker power plants have low capital cost and high operating cost, and often rely on a simple cycle gas turbine or run-of-the-river hydroelectric power. In general, they are actived only at peak demand periods. In (Stoft, 2002) mid-merit plants are defined as follows: These plants operate for more hours than peakers and fewer than base load plants, approximately 20 per cent to 60 per cent of the time. Midload plants are often started daily, but run for the most of the day not just a few peak hours. In other words, these power plant types set the system marginal cost much of the time; in a competitive market, they usually set the price.

The aggregate marginal cost curve for a typical pool of plants has costs that rise slowly over a range of generators, but rise rapidly as the overall capacity is approached. A marginal cost curve is presented as an illustration in Figure 2.2. The marginal cost curve becomes almost vertical as the capacity of the system is reached. As can be observed in Figure 2.2, if some of the capacity becomes unavailable (due to maintenance, withholding, or lack of enough installed capacity), SC_1 could shift up or left, for example to SC_2. Since electricity demand varies from month to month, from hour to hour, from year to year and can not be stored, system marginal costs oscillate in time.

However, as stated in (Borenstein and Bushnell, 2000), demand is virtually inelastic in the short run (for instance, during a day, demand may not be shifted from peak-hours from off-peak hours). On the other hand, the long-term price elasticity[2] of electricity demand is between -0.5 and -1.5 (Stoft, 2002). In economic analysis, the short run and long run are distinguished by different responses. The short run could be defined as a period of time in which consumer response is limited to more or less to the use of space conditioning (changing the thermostat setting), or lighting, with existing equipment. The long run period is of sufficient time that consumers can consider more efficient space conditioning equipment, variable speed motors and fans, and more efficient coating processes. For the market as a whole, the short run could be a year or less, and the long run up to five or ten years (Stevens and Lerner, 1996).

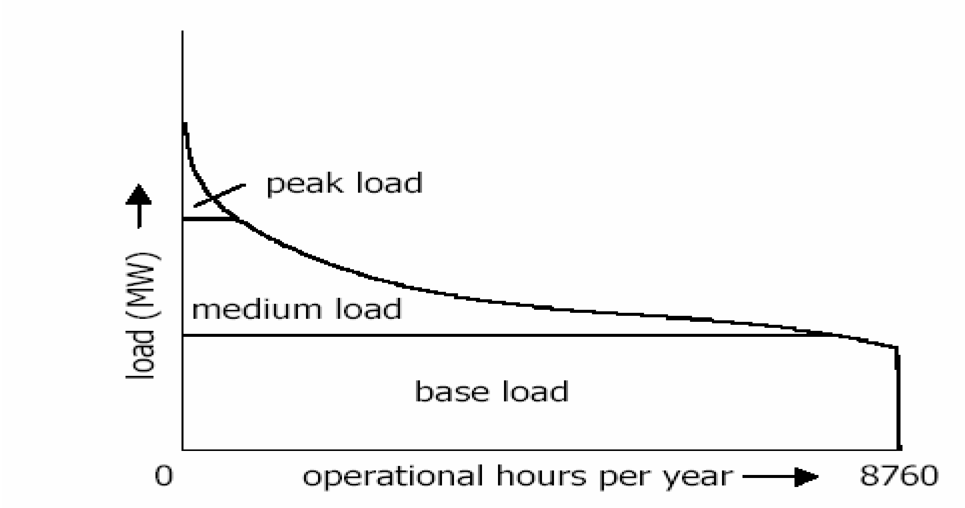


Figure 2.1. Sample load-duration Curve

2.3.2. Average Cost Versus Marginal Cost Pricing: Contract Prices and Spot Prices

In a deregulated market, marginal cost lies at the heart of the system. In some of the deregulated markets, electricity suppliers offer their bids (in terms of supply quantity and price based on their marginal costs) to the system operator. Then, the electricity price

[2] Price elasticity of electricity demand, shortly *electricity demand elasticity*, is defined as the percentage change in the electricity demand that occurs in response to a change in the electricity price. If demand elasticity is said to -0.5, this means that a 10 per cent change in price causes a 5 per cent change in demand.

(spot price) is determined by the intersection of supply and demand curves as illustrated in Figure 2.2. If there is a price which equilibrates supply and demand in a competitive market (i.e. there is a market clearing price), then the market and the price are also to be competitive. (Stoft, 2002). (i.e. If the market is competitive, this spot price should represent the short run marginal cost of generation.)

However, since electricity can not be stored and its short run supply and demand elasticities are almost negligible, producers can increase the spot price over the marginal costs, just by withholding a portion of their capacities. Therefore, besides the natural oscillations in demand, periodic capacity withholding tendencies of the producers is another factor increasing the oscillations of electricity prices. Marginal cost and time variant demand are explained via an example in the paragraph below.

Figure 2.2. demonstrates a set of demand curves that may represent demand at different times on a given system. For example, D_1 represents night time demand in the Spring or Fall, when demand is at its lowest, while D_2 is the night time demand in Winter when heating loads are high. On the other hand, D_3 represents an unusual peak demand. In Figure 2.2., 35, 50, 70 \$/MWh are the marginal costs of the time span, associated with demand patterns D_1, D_2, and D_3, respectively. The SC_2 curve in Figure 2.2. represents behavior of supply when some generation capacity is unavailable (it may be due to breakdowns, maintenance, producers' manipulations, increase in fuel costs), as it was observed in 2000 when rising leaps in gas prices increased generation costs for many utilities, most visibly in California. As illustrated in Figure 2.2., shifts in either supply or demand may distinctly increase or decrease the short run marginal cost, and thus the spot price, especially if the system is close to full capacity utilization.

In a regulated electricity market, price is fixed for a period of year to all customers in a class, whereas in a liberalized market all customers pay the spot price, which is time variant due to time variant demand.

The spot price may be efficient, but it can lead to variable electricity bills, and neither the consumers nor producers may not want to face drastically volatile bills, so that they opt for long-term contracts.

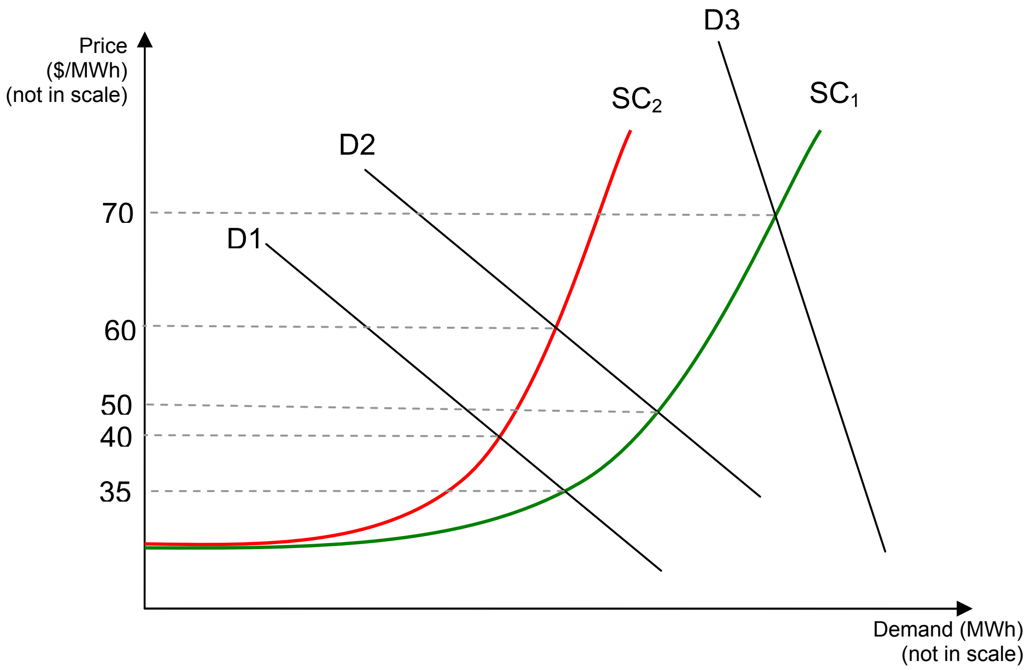


Figure 2.2. Marginal cost, demand curve and supply curve relationships

2.3.3. Power Plant Investments

In a regulated electricity market, with monopoly on generation, traditionally a central authority projects future demand and plans investment in new capacity to meet the forecasted supply-demand gap. In this environment, if the central authority's projections are pessimistic and/or if the central authority is very risk averse (regarding profits), real investment may well lag behind demand. On the other hand, if projections are optimistic and/or the central authority is risk prone (regarding profits), investment level may surpass demand. Indeed, in Turkey, one criticism of regulated utilities has been over-investment in facilities to minimize risks of power shortages and consumer complaints. Since construction times of power plants are long, investment planning of generation units is critical and difficult (for instance, it may take six years to construct a nuclear power plant, or to launch a hydro power plant).

If the market is diversified and competitive, then individual private investors will invest in new generation units, as long as expected market price is high enough to meet their return expectation on that investment, while at the same time they try to outguess their competitors in market expectations, mutual investment decisions and pricing policies. Besides, such investments would likely attract risk premiums that would increase with the lead time involved and increase with the fraction of the load that could not be sold at a fixed price for a decade or two. While it is widely believed that competition lowers the cost of new investments (by forcing investors rather than customers to bear the costs of unwise investments), this belief ignores the increased risk premium those investors will demand for taking the risk. As a consequence, cost of capital for competitive generators is distinctly greater than for a regulated utility making the same investment. Because of this reason, investors in the competitive environment expect higher rates of return from new investments, compared to investors in a regulated market.

Based on the above factors, we can say that, due to higher return expectations of the investors and long-lead times, there may be supply shortages in competitive and decentralized environments. In fact, supply shortages result in higher spot prices, which trigger new investments. On the other hand, if the high prices due to supply shortages prevail in the market for a long-time, then consumers may reduce their consumption levels, which may result in excess supply when the generation units under construction are introduced to the market. As a consequence, the spot price may drastically decrease.

To sum up, over time, competitive prices may follow a saw tooth pattern, rising until a new plant comes on line, then falling, only to rise again as demand grows. As a consequence, we can say that inescapable, interrelated and time based oscillations may exist in the demand side and supply side of the deregulated electricity market.

3. LITERATURE SURVEY

3.1. Multicriteria Decision Making (MCDM) Tools in Energy Problems

Multicriteria Decision Analysis (MCDA) describes any structured approach used to determine overall preferences among alternative options, where the options accomplish several objectives. In MCDA, desirable objectives are specified and corresponding attributes or indicators are identified. The actual measurement of indicators need not be in quantitative terms, but are often based on the qualitative terms. Different environmental and social indicators may be developed side by side with economic costs and benefits. (i.e. a variety of both quantitative and qualitative objectives may influence policy decisions, so they are sometimes needed to be considered simultaneously at the phase of policy decisions). MCDA provides techniques for comparing and ranking different outcomes, even though quantitative and qualitative indicators are used side by side. Multicriteria Decision Analysis or Multiobjective Decision Making is a type of decision analysis tool that is particularly applicable to cases where a single-criterion approach (such as cost-benefit analysis) is not sufficient, especially where significant environmental and social impacts cannot be assigned monetary values. MCDA allows decision makers to include a full range of social, environmental, technical, economic, and financial criteria. Most of the MCDA methods are based on the exercise of some expert judgment.

Some of the most widely used Multicriteria Decision Making Tools are;

- AHP (Analytical Hierarchical Process) proposed by (Saaty, 1977 and Saaty, 1980);
- PROMETHEE (Preference Ranking Organization Method for Enrichment Evaluation) developed by (Brans *et al.*, 1986);
- ELECTRE, (Roy, 1991 and Roy and Mousseau, 1996).

Let us briefly review some of the AHP, PROMETHEE and Electre implementation in the energy sector. In (Kagazyo *et al.*, 1997) energy related projects are evaluated and prioritized. The authors have used the AHP (Analytical Hierarchical Process) for incorporating resource and social aspects of the projects. Under the umbrella of technological issues, technical characteristics, environmental burden and cost are analyzed. The attributes of resource and social aspects are the following: resource, supply stability, social acceptance, international aspects and lead-time. The forwarded characteristics are also subdivided. By utilizing the estimated relative importance of each selected characteristic, seven different planning perspectives have been identified: short, intermediate, and long-range strategies for Japan; short and intermediate range strategies for less developed countries, and intermediate and long range global strategies.

In (Akash *et al.*, 1999) the AHP methodology has been used to perform a comparison between different electricity power plants in Jordan. The power plants considered in the study, in addition to fossil fuel power plants, are nuclear, solar, wind, hydro-power. Cost-to benefit ratios have been used to determine the best alternatives for electric power production.

In (Siskos and Hubert, 1983), the problem of comparison of energy alternatives from the social and public health point of view is considered. The method used is the ELECTRE type and is therefore based on the analysis of the concordance and discordance of criteria. Since fuzzy outranking relations are used to model the preferences, uncertainty is also considered in the study. Four different energy strategies have been generated and this allows the authors to take into consideration the points of view of the various social groups involved in the problem of energy choices. In this context, the views of an economist, a resource management, an electricity producer and a local public administrator have been analyzed in the study.

In (Goumas and Lygerou, 2000) PROMETHEE has been extended to deal with fuzzy input data. The method has been applied for the evaluation and ranking of alternative energy exploitation schemes of a low temperature geothermal field. It is stated that this approach is more realistic and produces a more reliable evaluation and ranking for alternatives, such as alternative energy exploitation scenarios, where the input data are not well defined.

In (Georgopoulou *et al.*, 96), the renewable energy sources in Greece are evaluated. Since, several and often conflicting points of view must be taken into account, in this paper

ELECTRE III has been used. Through the paper, identification of actors, selection of criteria, formulation of alternative strategies, application of ELECTRE III, analysis of results and actors' reactions are discussed.

In (Eleftheriadou *et al*., 2004), a methodological framework for site selection of renewable energy projects has been presented. The projects are evaluated regarding technological, economic, social, energy and environmental aspects by various decision makers. The PROMETHEE II method is used. The proposed methodology is applied in a case study for the further exploitation of the wind energy potential in the area of (Kratigos-Lesvos).

(Hobbs and Meier, 2000) summarize a wide range of multicriteria energy sector problems. The time scale for decisions extends from minutes (for generation system dispatch) to decades (for research and development), and the geographic scale varies from local (distribution reliability and local integrated resource planning) to national and international (defining environmental policies and sustainability). What all the problems have in common is that there are many alternatives to choose from, and that there are important tradeoffs among economic, technical, environmental and social objectives.

3.2. System Dynamics Models in Energy Policy and Planning

A large number of energy policy models have been developed by using systems dynamic approach since 1970's. Figure 2.1[3] illustrates the intellectual lineage from the introduction of System Dynamics (SD), to the energy model developments in centralized markets. In 1970's, the main environmental concern of the researchers was the potential consequences of resource depletion and pollution. (Meadows *et al.*, 1972) with their model World3[4] and their famous book "Limits to Growth", they the questions of "whether economic growth in US is limited by resource depletion or not", " Is there an overshoot?". The World3 model includes population and economic population growth, pollution and depletion of resources. World3 is followed by various studies as indicated in Figure 2.1. The first one (Naill, 1973) implemented SD in the energy sector. His study includes all

[3] Source: US DOE, 1997
[4] World3 is the first study in this area and it is also cited in Figure 2.1.

sources of energy and energy demand. This study is followed by COAL 1, COAL2, FOSSIL1, FOSSIL2 and IDEAS (Integrated Dynamic Energy Analysis Simulation). IDEAS is a dynamic long-term policy simulation model of the US energy supply and demand, used by the US Department of Energy. It has been deployed to analyze US dependency on oil imports and to shape several national energy plans, (for example, the cost effectiveness of US policies to mitigate global warming). The main sectors of the IDEAS model are the energy demand and conservation, electricity generation, oil and gas, coal production, renewables and emissions. (Naill *et al.*, 1991).

A successor of the IDEAS model due to (Backus and Amlin, 1985) is called Energy 2020. This is a multi-fuel model aimed to provide decision making support to local level public administrators and to the decision makers of single utilities. It can be used for the analysis of supply, demand and price, for all types of fuels.

The lack of feedback in the existing energy models with the rest of the economy is criticized in (Sterman, 1981). This researcher has developed an energy-economy model to address the importance of energy-economy relationships.

SD models have a wide range of applications in the decentralized electricity sector as well (see (Ford, 1999) for a comprehensive overview). Rather than a general model, several smaller models exist to handle various problems, including particular regulatory-finance problems for utilities (Ford and Mann, 1983), hydropower and water management, and utility conservation programs.

Deregulation has brought new challenges to the electricity generation and transmission industry, and to the regulators. SD methodology has been used for the analysis of the privatization and deregulation processes of electricity markets all over the world (Bunn and Larsen, 1992; Bunn *et al.*, 1997; Vlahos, 1998). A SD model and analysis investment cycles (boom and busts) observed in the United States' electricity market is presented in (Ford, 1999a; Ford, 2001). The liberalization of the Columbian energy market has also been analyzed in (Dyner and Larsen, 1997) through SD methodology.

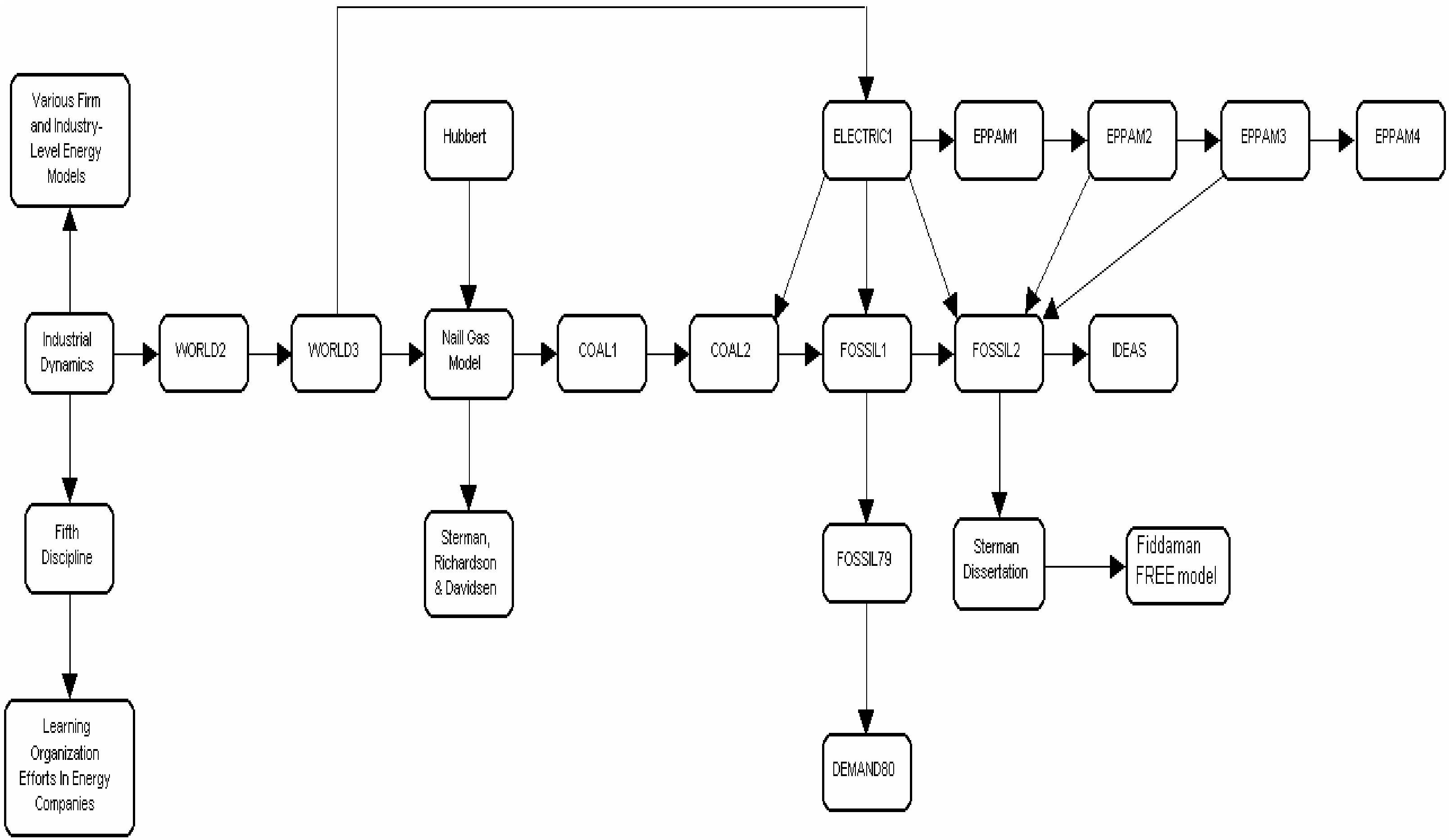


Figure 3.1. Intellectual lineage of SD energy modelling

4. AN ANALYSIS OF INVESTORS' POWER PLANT PREFERENCES THROUGH THE ANALYTICAL HIERARCHY PROCESS

4.1. Introduction

In this thesis, an Analytical Hierarchy Process (AHP) study is conducted to evaluate and compare the relative overall efficiency and attractiveness of power plant investment alternatives in Turkey. The developed AHP model incorporates technical characteristics, resource availability, socioeconomic, environmental, cost, political, legal and organizational aspects, for evaluating and prioritizing power plant types such as solar, nuclear, wind, hard coal, lignite, natural gas, petroleum and hydro plants. In the development process many experts, representing different sectors of the energy market in Turkey (experts and managers from energy related regulatory bodies, financial institutions, environmental groups, non governmental organizations, generation, transmission and distribution companies) have been consulted. The aggregated results obtained via this AHP model is used as a scenario option in the SD model, as mentioned in Section 7.2.

4.2. General Overview to AHP

The AHP, developed by (Saaty, 1980) in the early of 1970's, is a general process of measurement, in the sense of providing a structured and well defined methodology to convert decision makers' (or any other stakeholders') subjective preferences to quantitative, measurable gradings. It is used to derive ratio scales from both discrete and continuous paired comparisons in multilevel hierarchic structures. These comparisons may be taken from actual measurements or from a fundamental scale that reflects the relative strength of preferences. It has found its widest applications in multicriteria decision making, in planning and resource allocation, and in conflict resolution (Saaty,1983). It is a systematic procedure for representing the elements of any problem; it organizes the basic rationality by breaking down a problem into its smaller constituent parts and then calls for only simple pairwise comparison judgments to develop priorities in each hierarchy. It provides a comprehensive framework to cope with the intuitive, the rational, and the irrational in the decision makers all at the same time. It is a method that can be used to integrate the decision maker's perceptions and purposes into an overall synthesis. The AHP does not require that judgments be consistent or even transitive. One of its unique features is its ability to compute a measure of the inconsistencies made by the decision makers. This enables the decision makers to identify "errors," revise their judgments, and improve the quality of their decision. The basic principles and steps of the AHP are discussed below.

i. Step 1. This step consists of breaking down the decision problem into a hierarchical structure. Figure 4.1. illustrates a basic hierarchy made up of four levels. The top level represents the general goal under consideration. The second level represents the criteria relevant to this goal. For greater precision, the criteria may be divided into subcriteria, creating an additional level in the hierarchy (the third level). Finally the available alternatives are comparatively evaluated regarding the relevant lowest level subcriteria.

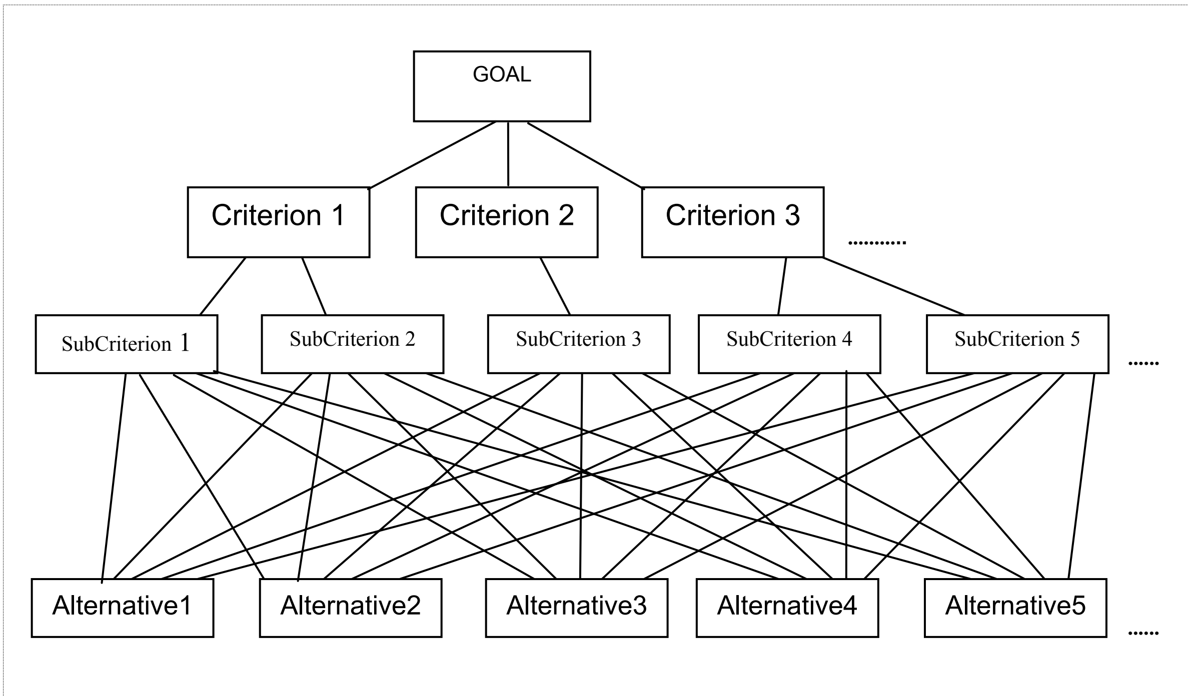


Figure 4.1. The basic structure of a hierarchy.

ii. Step 2. The second step involves evaluating the alternatives and weighing the criteria. The alternatives are pairwise compared to assess their relative performance with respect to each of the subcriteria. Similarly, the subcriteria are pairwise compared to measure their importance with respect to the criteria they belong. Finaly the criteria are pairwise compared, based on hard data, as well as on the intuition, experience, and expertise of the evaluator/decision maker. Therefore, the AHP explicitly allows for subjective judgments and recognizes their legitimate role in ex ante analysis. The fundamental scale presented in Table 4.1 is used to elicit the comparisons. The use of verbal value judgments in comparisons facilitate the qualitative weighting of subcriteria/criteria, while providing a simple and straightforward convertion mechanism for obtaining quantitative gradings for alternatives, subcriteria and criteria, through the assignment of numerical counterparts to the qualitative value judgments. So, once the qualitative comparisons are made, they are translated into the numerical values of the fundamental scale. Each set of comparative judgments is then entered into a separate matrix to derive the so-called "local" priorities, i.e., the preferences of the alternatives with respect to a specific criterion. The weights of the subcriteria and then the criteria are derived in a similar fashion.

Table 4.2. depicts the type of matrix used to enter the pairwise comparisons. The comparison of Alternative 1 with Alternative 2, for instance, yields the value a_{12}. For obvious reasons, the diagonal cells always contain the value 1. If the judgments were perfectly consistent, any column of the completed matrix could simply be normalized to yield the respective "local" priority of the alternative, i.e., its relative performance regarding criterion X. However, the judgments may not be consistent, therefore the eigenvector method (Saaty, 1977) is used to compute the these values.

Table 4.1. The fundamental scale for comparative judgments

Numerical values	**Verbal terms**
1	Equally important, likely or preferred
3	Moderately more important, likely or preferred
5	Strongly more important, likely or preferred
7	Very strongly important, likely or preferred
9	Extremely more important, likely or preferred
2, 4, 6, 8	Intermediate values to reflect compromise

Table 4.2. The matrix to derive local priorities

	Alternative 1	**Alternative 2**	**Alternative 3**	**Local Priority**
Alternative 1	1	a_{12}	a_{13}	
Alternative 2	a_{21}	1	a_{23}	
Alternative 3	a_{31}	a_{32}	1	

iii. Step 3. The third step consists of synthesizing the local priorities throughout the hierarchy, in order to compute the global priorities of the alternatives. The principle of hierarchic composition is applied for this task (Saaty 1980). The principle simply states that, for each alternative, the local priorities are multiplied by the corresponding criterion weight, and the results are summed up to obtain the global priority of the alternative with respect to the goal stated at the top level.

The major reasons why AHP technique is implemented in this study are given below;

i. The AHP facilitates the collection of all the relevant elements of the problem, whether objective or subjective, into one model and then to interactively work out their interdependencies and their perceived consequences.
ii. It features an inconsistency measure as a means for measuring the logical consistency of the decision maker's judgements. Users find it very much beneficial to have available numeric information regarding the logical inconsistencies in their judgments, especially if they are working as a group. In fact, the AHP is the only approach for solving multicriteria decision problems that has such a capability (Carlsson and Walden, 1995).

Although, the AHP has the above advantages, it has the disadvantages cited below, as well.

i. The AHP users must rely too heavily on their experience and intuitive judgment.
ii. The AHP also has a problem called rank reversal that is the reversal of the preference order of the alternatives when new options are introduced in the problem.

4.3. The Developed AHP Model

This section introduces the developed AHP model to facilitate comparative evaluations among the different electricity power plant investment options in Turkey. The power plant alternatives, evaluated via the developed AHP model, are hydro, natural gas, wind, lignite, solar, hard coal, petroleum and nuclear power plants. Throughout the development of the related AHP model, the following procedure is implemented.

i. The preparation of the draft AHP hierarchy tree.
ii. The preparation of the relevant questionnaire (i.e. set of questions and definitions for the many pairwise comparisons earmarked by the AHP tree.)
iii. Interviews with experts, who represent different groups of stakeholders (The Energy Market Regulatory Authorithy, NGOs focusing on environment and energy, academicians, raw material/service suppliers and financial organizations) are made in order to improve upon the developed AHP model and the questionnaire.
iv. The AHP model and the questionnaire is revised.Then, the implementation of the pairwise comparisons by the experts takes place at this phase.
v. Execution of the mathematical computations (i.e. aggregation of the individual experts' judgments and the matrix/eigenvalue computations).

The developed AHP tree (the main-criteria and sub-criteria for the evaluation of alternative electricity power plant types) is presented in Figure 4.2.

The decision making process for the choice of a future strategy in electricity generation is very complex, as it involves a large number of actors with often conflicting objectives. Expert and stakeholder opinions provide valuable insight into the parameters of the models to be developed. In this study, the experts, (who have assigned the weights to the criteria presented in Figure 4.3) are from the power generation/transmission/ distribution (G/T/D) sector (private and state companies), the finance sector (non-state organizations) and environmental and energy related NGOs. Distribution and listing of the affiliations of the experts consulted in this study is presented in Table 4.3. As it can be observed from this Table, totally 20 experts/stakeholders from different aspects of the energy sector have been consulted. Thirteen of these experts are from the (G/T/D) sector (six being from state companies and seven experts/stakeholders from private companies.)

Additionally, there are three experts/stakeholders from NGOs focusing on Environment and Energy, and four from Financial Organizations (FO).

In order to facilitate the proper execution of stages (vi) and (v) of the procedure described above, a problem specific, user-friendly AHP tool, is developed and utilized. Each expert/stakeholder consulted for pairwise comparisons, filled the related questionnaires via this tool. This tool also provided to the interviewees information on the terminology used in the developed AHP-tree and the objective of the study. It then directed the interviewees to the related spread-sheets, containing the specific questions related with the pairwise comparisons. Additionally, at the end of each questionnaire sheet (screen) consistency check is made automatically and the user is warned. This feature of the developed tool enabled the experts to take note of their logic “errors”, and revise their judgments (if they so desire), in order to improve the quality of their evaluations.

Table 4.3. Distribution of the experts’ affiliations

Affiliation	**Number**	
G/T/D Public State	 6 7	13
NGO		3
FO		4
Total		20

4.4. Results and Discussions

Aggregated results of the interviewees’ responses are given in detail through Tables 4.4- 4.9. As can be observed from Table 4.4, monetary cost is the most important criteria in the overall. Cost is followed by technical characteristics and resource availability criteria. Surprisingly, environmental factors are the least important criteria for all expert groups. Table 4.6. illustrates the preference weights assigned by expert groups to each power plant type under consideration. As can be observed from this table, nuclear power plants are the least preferred plant types, wheras hydro power plants, natural gas and wind power plants are the most prefered ones, in descending order. Table 4.8 and Table 4.9 present weights and ranks assigned to sub-criterias by each expert/stakeholder group. As can be observed from these tables, supply reliability and investment costs are perceived as the most important factors, wheras decommissioning costs and compliance with international environmental law are perceived as the least important factors. Figure 4.3 and Figure 4.4 display the order of preference and weights assigned by each expert group to the plant types and main-criteria. Here, it is important to note that, hydro power plants are the most preferred plant types bt the G/T/Ds and NGOs focusing on environment and energy, wheras financial organizations prefer wind and natural gas plants the most.

By means of the developed AHP model, expert opinions have been channeled to provide valuable insight into investment decision of the passive investors, which are driven by the computer, by utilizing the default decision rules. In the developed SD model, there are eight different power plant types and in the default setting all passive investors check the profitability and primary energy resources' reserve availability of these eight power plant types and then invest in the profitable ones, within their available primary energy resources' reserves. To see market behaviors in case the investors would like to consider less than eight power plant types as candidate investment alternatives, two additional options are offered to the LEMM-user. In the first option, all passive investors invest in only the power plant types ranked as the first four in the aggregated AHP results (as long as the related plant types have non-negative net present value and there exists sufficient primary energy resources' reserves). In the second option, all passive investors invest in only the plant types ranked as the first three in the AHP results (again, as long as the related plants have non-negative net present value and there exists sufficient primary energy resources' reserves).

On the other hand, the power plant types considered in the developed SD model is determined based on the interviews made throughout the AHP study. The interviewees suggested us to categorize hydro power plants under two categories, large and small hydro plants (which are less than 100 MW). Additionally, they suggested the inclusion of geothermal plants rather than solar plants. Besides, as the aggregated AHP results revealed that nuclear plants are the least preferred plants, nuclear plants are not considered in the SD model. (However, the SD model is sufficiently flexible to include new plant types, if so desired).

It should also be stated that the number of the interviews conducted so far is not sufficient to fully represent the energy sector. Actually, the developed AHP tool is delivered to around 80 experts in the energy sector, but unfortunately the response rate has been a quarter of this number.

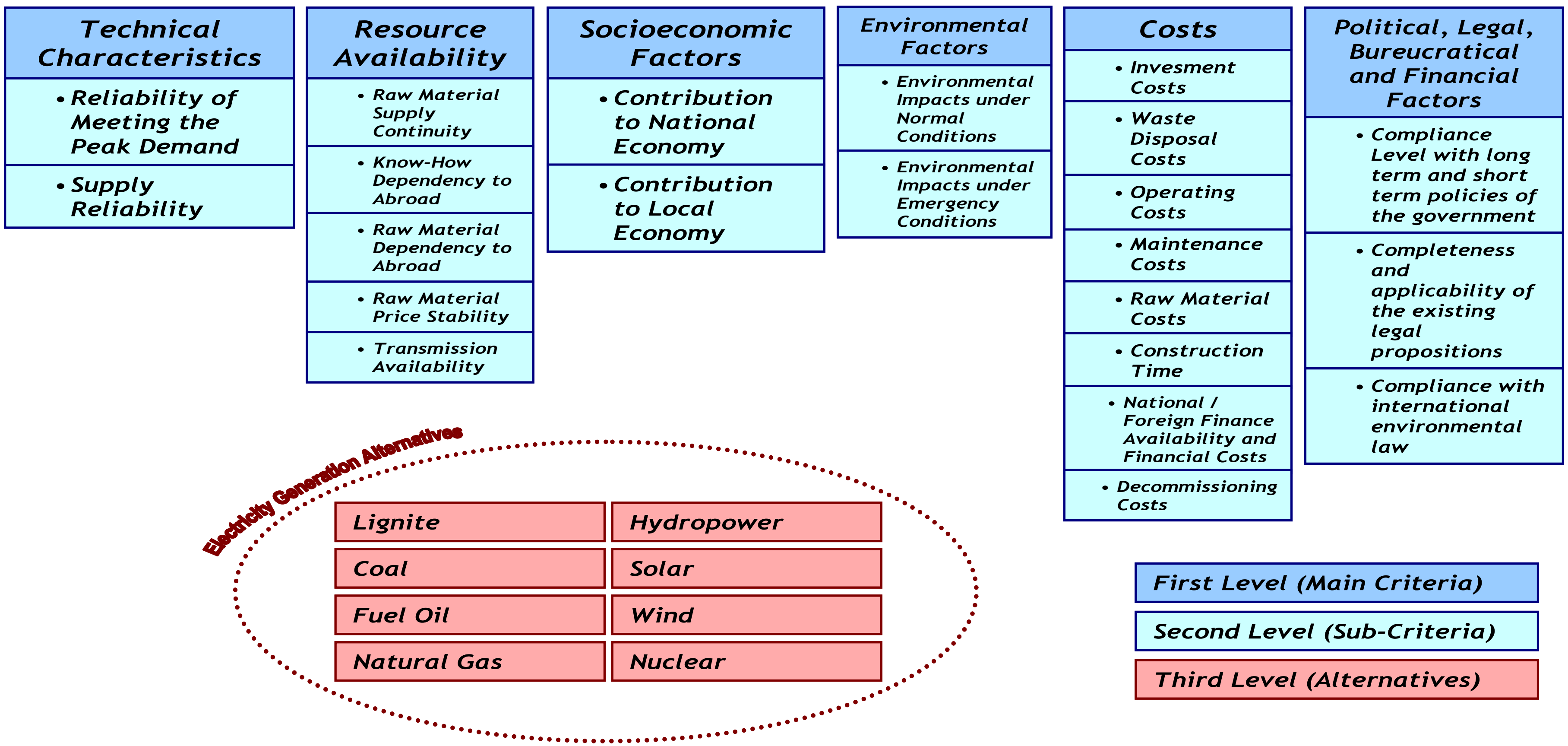


Figure 4.2. The developed AHP tree

Table 4.4. Preferences for the main criteria (per cent)

MAIN CRITERIA	OVERALL	All G/T/Ds	State G/T/Ds	Private G/T/Ds	Non State	Finance Sector	Environme-ntalists	Non G/T/Ds
Costs	32.2	30.1	26.1	33.4	35.0	37.0	36.6	36.8
Technical Charcteristics	18.9	19.0	14.4	22.8	20.9	12.3	28.3	18.7
Resource Availablity	18.1	21.8	23.9	20.1	15.5	8.9	11.8	10.0
Socioecenomic Factors	11.8	11.2	18.1	5.4	8.9	17.7	6.3	13.3
Political, Legal, Bureuctatical and Financial Factors	9.7	8.8	4.8	12.2	12.0	14.7	7.2	11.7
Environmental Factors	9.3	9.1	12.7	6.1	7.7	9.4	9.8	9.5

Table 4.5. Preferences for the main criteria (ranks)

MAIN CRITERIA	OVERALL	All G/T/Ds	State G/T/Ds	Private G/T/Ds	Non State	Finance Sector	Environme-ntalists	Non G/T/Ds
Costs	1	1	1	1	1	1	1	1
Technical Charcteristics	2	3	4	2	2	4	2	2
Resource Availablity	3	2	2	3	3	6	3	5
Socioecenomic Factors	4	4	3	6	5	2	6	3
Political, Legal, Bureuctatical and Financial Factors	5	6	6	4	4	3	5	4
Environmental Factors	6	5	5	5	6	5	4	6

Table 4.6. Preferences for plant types (per cent)

MAIN CRITERIA	**OVERALL**	**All G/T/Ds**	**State G/T/Ds**	**Private G/T/Ds**	**Non State**	**Finance Sector**	**Environme-ntalists**	**Non G/T/Ds**
Hydropower	19.1	20.6	20.0	18.7	17.3	11.9	18.1	14.4
Natural Gas	14.4	14.6	11.5	16.5	15.5	16.1	15.8	13.9
Wind	13.6	13.3	12.8	13.1	13.8	16.9	10.0	15.9
Lignite	12.7	12.5	16.1	11.6	12.0	11.8	12.3	12.3
Solar	12.6	12.7	11.5	12.8	13.1	14.1	8.9	14.1
Hard Coal	11.0	10.4	12.3	9.7	10.8	11.8	12.4	12.3
Petroleum	9.5	9.9	9.0	9.9	9.2	10.1	7.5	7.8
Nuclear	7.1	6.0	6.8	7.7	8.3	7.3	15.0	9.3

Table 4.7. Preferences for plant types (ranks)

MAIN CRITERIA	**OVERALL**	**All G/T/Ds**	**State G/T/Ds**	**Private G/T/Ds**	**Non State**	**Finance Sector**	**Environme-ntalists**	**Non G/T/Ds**
Hydropower	1	1	1	1	1	4	1	2
Natural Gas	2	2	5	2	2	2	2	4
Wind	3	3	3	3	3	1	6	1
Lignite	4	5	2	5	5	5	5	5
Solar	5	4	5	4	4	3	7	3
Hard Coal	6	6	4	7	6	5	4	5
Petroleum	7	7	7	6	7	7	8	8
Nuclear	8	8	8	8	8	8	3	7

Table 4.8. Preferences for sub-criteria (per cent)

MAIN CRITERIA	OVERALL	All G/T/Ds	State G/T/Ds	Private G/T/Ds	Non State	Finance Sector	Environme-ntalists	Non G/T/Ds
Supply Reliability	13.6	12.5	9.8	15.1	15.4	10.3	24.0	15.7
Investment Costs	9.8	8.4	6.2	10.4	11.5	12.4	13.2	12.7
Contribution to National Economy	9.2	8.9	15.0	4.1	6.6	13.5	3.7	9.6
Environmental Impacts under Normal Conditions	7.1	7.0	10.6	4.0	5.5	6.4	8.5	7.3
Raw Material Costs	6.7	6.7	7.6	5.8	6.2	6.7	6.8	6.7
Raw Material Suppy Continuity	5.4	6.0	7.5	4.7	4.4	3.6	4.9	4.1
Reliability of Meeting the Peak Demand	5.3	6.4	4.7	7.7	5.5	2.0	4.3	2.9
National/Forein Finance Availability and Financial Costs	4.6	4.4	2.4	6.1	5.6	7.3	1.5	5.0
Completeness and Applicability of the Existing Legal Propositions	4.3	3.5	1.8	4.9	5.4	8.7	2.2	6.1
Raw Material Dependency to Abroad	4.3	5.6	6.5	4.8	3.3	1.2	2.0	1.5
Compliance Level with Long-and Short-term Government Policies	3.9	3.8	1.4	5.7	5.1	4.3	4.2	4.3
Raw Material Price Stability	3.8	4.2	2.4	5.6	4.5	2.7	3.7	3.1
Operating Costs	3.4	3.2	3.1	3.3	3.5	2.7	5.5	3.8
Knowhow Dependency to Abroad	2.6	3.6	5.2	2.3	1.5	0.5	0.5	0.5
Maintenance Costs	2.6	2.9	2.5	3.2	2.6	1.6	2.6	2.0
Contribution to Local Economy	2.6	2.2	3.3	1.2	2.3	4.2	2.5	3.5
Construction Time	2.4	2.1	1.5	2.7	2.9	3.0	3.4	3.2
Environmental Impacts in Emergency Conditions	2.2	2.2	2.2	2.1	2.2	2.9	1.3	2.3
Transnmissions Availability	2.0	2.5	2.2	2.7	1.8	0.8	0.7	0.8
Waste Disposal Costs	1.8	1.6	1.9	1.2	1.8	2.6	2.2	2.4
Compliance with International Environmental Law	1.5	1.5	1.4	1.6	1.5	1.8	0.8	1.4
Decomissioning Costs	0.9	0.8	0.8	0.8	0.9	0.8	1.5	1.1

Table 4.9. Preferences for sub-criteria (ranks)

MAIN CRITERIA	OVERALL	All G/T/Ds	State G/T/Ds	Private G/T/Ds	Non State	Finance Sector	Environme-ntalists	Non G/T/Ds
Supply Reliability	1	1	3	1	1	3	1	1
Investment Costs	2	3	7	2	2	2	2	2
Contribution to National Economy	3	2	1	11	3	1	9	3
Environmental Impacts under Normal Conditions	4	4	2	12	7	7	3	4
Raw Material Costs	5	5	4	5	4	6	4	5
Raw Material Suppy Continuity	6	7	5	10	11	10	6	9
Reliability of Meeting the Peak Demand	7	6	9	3	6	16	7	14
National/Forein Finance Availability and Financial Costs	8	9	14	4	5	5	17	7
Completeness and Applicability of the Existing Legal Propositions	9	13	18	8	8	4	14	6
Raw Material Dependency to Abroad	10	8	6	9	13	19	16	18
Compliance Level with Long-and Short-term Government Policies	11	11	20	6	9	8	8	8
Raw Material Price Stability	12	10	13	7	10	13	10	13
Operating Costs	13	14	11	13	12	14	5	10
Knowhow Dependency to Abroad	14	12	8	17	21	22	22	22
Maintenance Costs	15	15	12	14	15	18	12	17
Contribution to Local Economy	16	18	10	20	16	9	13	11
Construction Time	17	19	19	16	14	11	11	12
Environmental Impacts in Emergency Conditions	18	17	16	18	17	12	19	16
Transmissions Availability	19	16	15	15	18	20	21	21
Waste Disposal Costs	20	20	17	21	19	15	15	15
Compliance with International Environmental Law	21	21	21	19	20	17	20	19
Decomissioning Costs	22	22	22	22	22	21	18	20

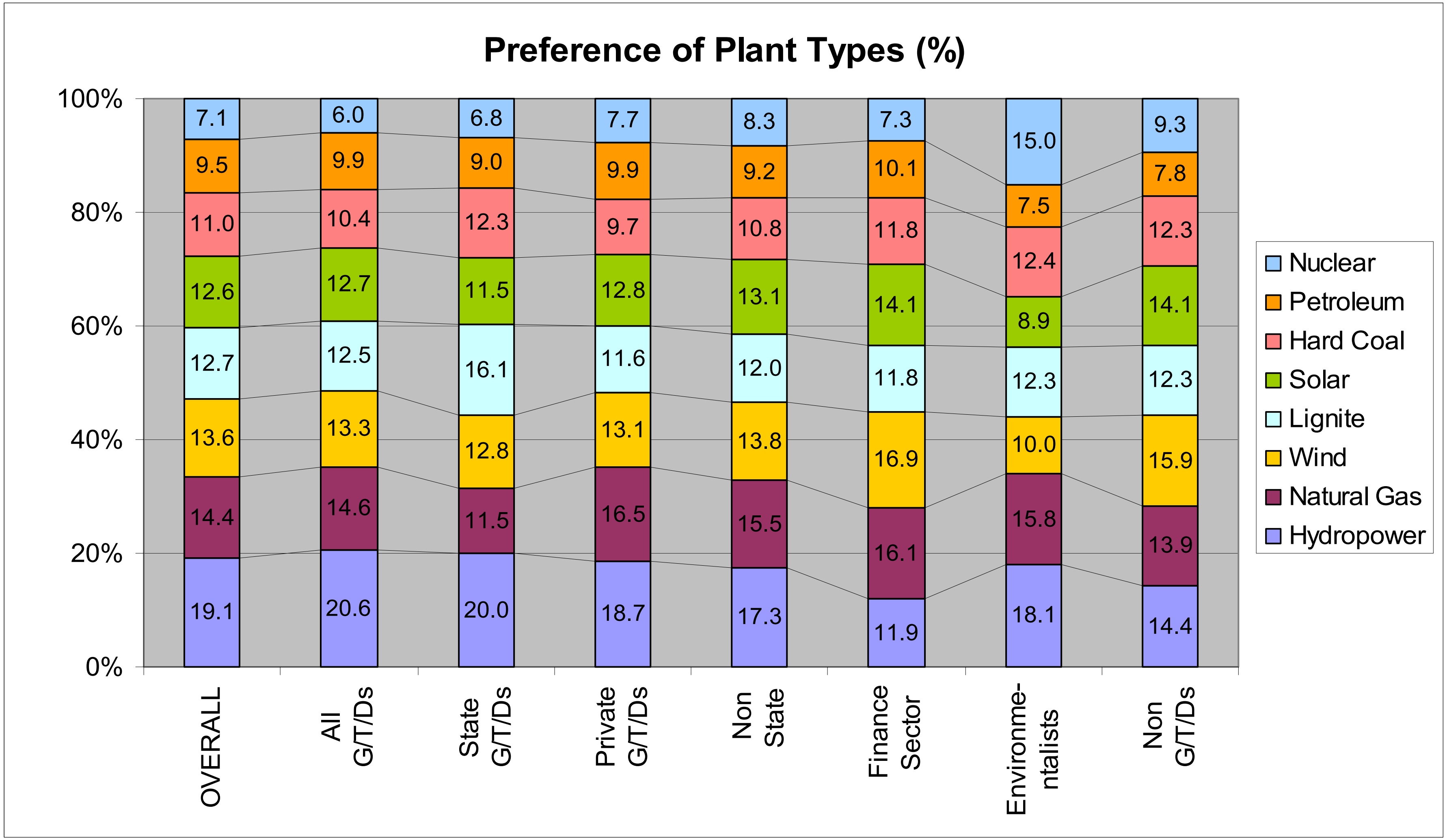


Figure 4.3. Histogram of each expert group's preference for plant types

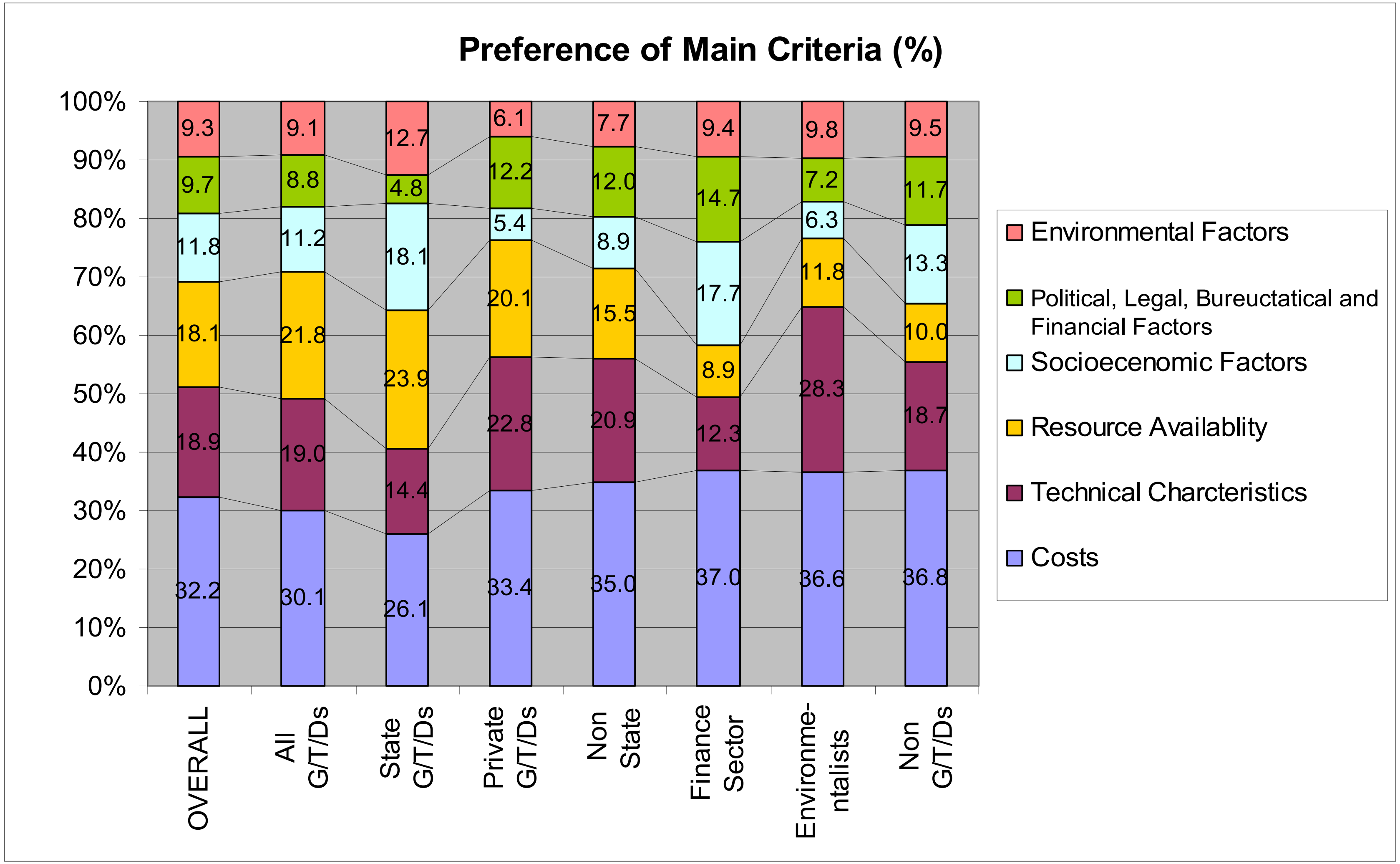


Figure 4.4. Histogram of each expert group's preference for the main-criteria

5. SYSTEM DYNAMICS MODEL OF THE LIBERALIZED ELECTRICITY MARKET

5.1. Introduction

After the liberalization of the electricity generation industry, capacity expansion decisions are made by multiple, independent power companies. Unlike the centralized environment, decision-making of market participants is now guided by price signal feedbacks and by an imperfect foresight of the future market conditions (and competitor actions) that they will face. In such an environment, decision makers need to better understand long-term dynamics of the supply and demand sides of the power market. To visualize the competitive electricity power market dynamics, a simulation model based on SD philosophy is developed in this study, and the proposed model is presented throughout this chapter.

The developed model includes a demand module, a capacity expansion module, an accounting and financial module, and a bidding mechanism involving up to five competitors (the power pooling system). By means of such a decision tool, companies and regulators have a better opportunity to understand possible consequences of different strategic and tactical decisions that they may make under different policies and market conditions.

5.1.1. Modeling for Predicting versus Modeling for Learning

The "dynamics" in "System Dynamics" refers to the fundamental patterns of change such as growth, decay and oscillations. SD models are constructed to help us understand why these patterns occur. The main purpose is improved understanding and learning, not point prediction (Ford, 1999b). In other words, SD model are descriptive, not predictive.

Predictive models are quite different than descriptive models. They are used to predict a value of an important variable at some point in the future (for instance weather forecast). Since their purpose is well defined, predictive models are easily evaluated: while judging the performance of these models, it is just focused on "how frequently their predictions turn out to be correct". Predictive methods are useful in clearly defined situations, where point forecasts are needed and predictive methods can be evaluated. On the other hand, descriptive models are suitable for situations/environments not clearly defined, and as such, they are more difficult to evaluate.

SD simulations are usually deployed in pairs. By comparing one simulation against the other (obtained via changing the value of various parameters, including additional factors in the market etc.), the model serves its intended purposes of learning, understanding and offers rules of thumb.

The proposed model in this thesis differs from the traditional models of the electricity market by being descriptive, rather than prescriptive.

5.1.2. Basic Features of SD Models

SD is an approach of modeling the dynamics of complex systems such as population, ecological, biological and economic systems, which usually interact strongly with each other. System Dynamics was founded in the early 1960s by Jay W. Forrester, with the establishment of the MIT SD Group. At that time, Forrester began applying what he had learned about systems during his work in electrical engineering to every kind of systems faced in daily life. The difference between SD and other approaches studying on the complex systems is that SD focuses on feedback loops.

SD attempts to understand the basic structure of a system, and thus understand the behavior produced by the underlying structure. SD takes advantage of the fact that a computer model can be of much greater complexity and carry out more simultaneous calculations than the human mind can do. Computer softwares such as Stella, Powersim, Vensim are used to develop and execute a SD model of the situation being studied. Simulating "what if" scenarios to test certain policies on such a model can greatly aid in understanding how the system changes over time.

Stocks and flows are the basic building blocks of a SD model. They help to describe how a system is connected by feedback loops which are one of the main causes of nonlinearities found so frequently in daily life problems. Stocks, in other words levels, represent accumulations in the system. Stock variables are the integration of the flow variables that influence them over time (i.e. stocks are the accumulation of the flow variables over time). Flows are interpreted as change in stocks over time. Due to this reason, flow variables are also called as “rate variables”. For example if the annual electricity demand growth is flow, then the current electricity demand in the market is a stock variable. Stocks are represented by boxes, whereas flows are represented by valves on arrows that either flow in or out of stock variables. Figure 5.1. demonstrates how a stock and rate variables (inflow and outflow variables changing the stock over time) are represented in model diagrams.

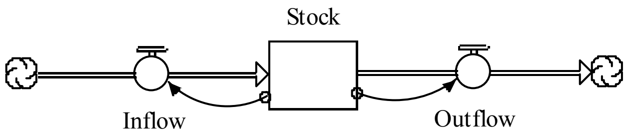


Figure 5.1. Representation of stock and flow variables in model diagrams

The SD approach can be summarized in the following five iterative steps, as illustrated in Figure 5.2 (these five steps are presented in detail in (Sterman, 2000), and Figure 5.2. is a modified version of the Figure 3-1 of this work)

1. Problem Articulation. In this step, the problem and the boundary of the system, (in which the problem lies), is identified. Based on the problem and the boundary of the system, some of the variables in the model are defined as endogenous, and some as exogenous.
2. Hypothesis Formulation. A dynamic hypothesis is then developed in terms of a causal loop diagram, stock and flow diagrams. Figure 5.3. demonstrates rules of causal loop diagrams.
3. Model Building. Based on the first two steps, the dynamic model is built in the third step. Initial parameter values, equations identifying the interactions and relationships between model variables are defined at this phase of the modeling.
4. Testing of the model. The verification (internal consistency) and validation (suitability to the real problem) of the dynamic model is conducted in the fourth step. Comparing the simulated behavior of the model to the actual behavior of the system is a part of testing the developed model. The sensitivity of model behavior

and policy recommendations to the different values of the important variables must be assessed. Every equation must be checked for dimensional consistency. Extreme condition tests should be conducted.

5. Policy Design and Analysis. When reasonable confidence in the model is achieved, policy design and analysis can take place. Policy design is much more than changing the values of individual parameters. Policy design includes the creation of entirely new strategies, structures and decision rules. The robustness of policies and their sensitivity to uncertainties in model parameters and structure must be assessed, including their performance under a wide range of alternative scenarios. The interactions of different policies must also be considered: Because, the investigated real systems are highly nonlinear, the impact of combination policies is usually not the sum of their impacts alone. Often policies interfere with one another; sometimes they reinforce one another and generate substantial synergies.

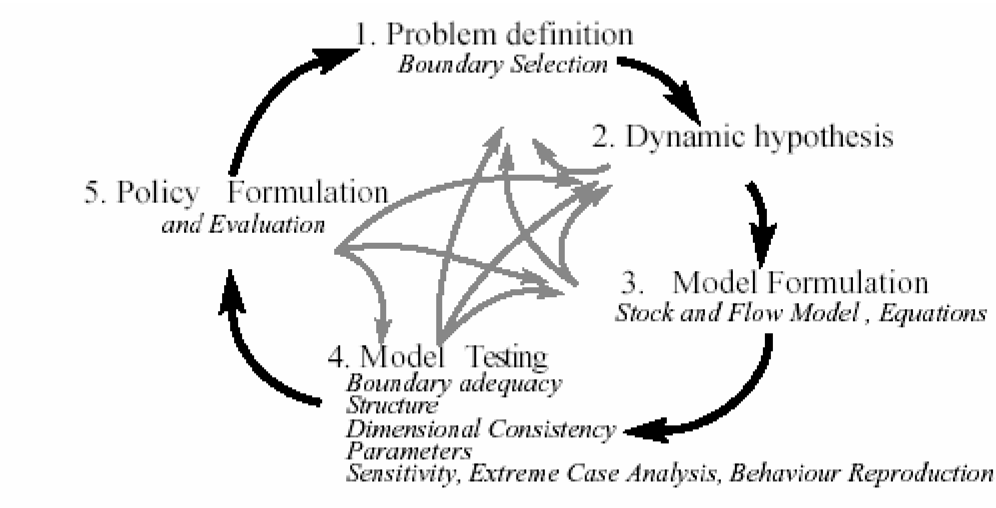


Figure 5.2. Iterative steps in modeling by using system dynamics approach

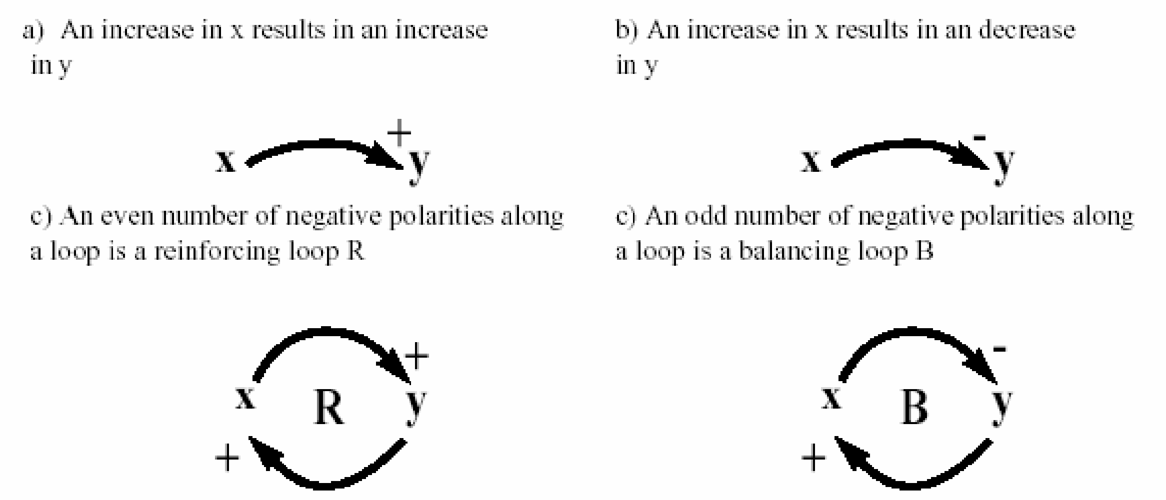


Figure 5.3. Rules of causal loop diagrams (CLD)

Added to the five steps forwarded above, if the model-builder aims to convert the proposed model to an interactive simulator, a microworld, he/she should proceed the following steps. First, the variables controlled by the player should be determined. Then, the SD model is modified in order to allow interactive input which may imply structural change in the model. After developing the interface of the model, proposed microworld is presented to the different players so that understand and improve the players' perception of the system.

5.1.3. Why System Dynamics Used in the Proposed Model?

The limitations of traditional energy modeling approaches (i.e. optimization) presented in (Bunn and Dyner, 1996) are that they are inherently prescriptive, linear, mechanistic, while ignoring important feedbacks and being non-behavioral. (Dyner and Larsen, 2000) point out how the fundamental assumptions underlying modeling methods in monopolistic markets have changed from planning to designing strategy in a liberalized market, requiring complementary modeling approaches such as agent based models, SD, game theory, financial risk modeling, real options in addition to the traditional approaches.

(Ford, 1996) also presents usefulness of SD as a modeling approach within the utility industry. In addition, a group of experienced members from utilities gathered to systematically run and compare decision support models in Utility Modeling Forum (EPRI 1981; Ford and Mann 1983). The SD model was far less detailed, had fewer equations, and costed less to develop than the other models. On the other hand, as the testing progressed, System Dynamics' unique feedback mechanisms pointed out parts of reality that that were dismissed in the other models. As a consequence, outputs of the other models were significantly different from the results obtained via System Dynamics model.

As mentioned in the previous sections, SD focuses on learning and understanding the system (instead of predicting the future). Accordingly, to visualize the liberalized and decentralized electricity power market dynamics, a simulation model based on System Dynamics philosophy has been developed in this study.

5.2. The Structure of the Proposed Model

5.2.1. General characteristics of the Model

In this study, the post–deregulated Electricity Market is modeled based on SD approach, through STELLA 7.01 R. The model simulates the behavior and operation of the liberalized and decentralized power market for a 20 years period, on a monthly basis. Additionally, in the microworld version of the model, simulation runs pause every five years, so that the player can update various parameters defining current market conditions, such as interest rates, subsidies/surcharges, investment cost of power plant technologies etc.

The situation that players are faced with, at the beginning of the simulation, is a market that has recently been opened to competition. At the heart of the model, there is electricity pooling system (explained in Section 5.2.6).

Constraints on transmission capacity between the various regions are not considered in the model.

During the modeling process, various submodels have been developed and tested before they were integrated to form a complete system model. At each phase of the modeling, besides literature, expert opinions have been consulted in determining the model structure, relationship between entities, parameters and equations used in the model. During the study 128 different scenarios have been configured, run and analyzed.

After scenario analysis is completed, a user-friendly interface is added to the model, the decision tool, LEMM (Liberalized Electricity Market Microworld) has been completed. LEMM is presented in Chapter 7.

5.2.2. Bull's Eye Diagram of the Model

In Figure 5.4. a bull's-eye diagram of the model is presented. In a bull's eye diagram, endogenous variables are placed in the center of the bull's-eye; exogenous variables are placed in the outer frame. Excluded variables are placed outside the outer frame. The bull's-eye diagram is a concise way to demonstrate the model focus, the required inputs, and the system boundary of the model (Ford, 1999b).

It is also a convenient way to show the relative balance between required inputs and endogenous variables. A quick glance at bull's-eye diagram reveals whether endogenous variables are more than exogenous variables or not. If endogenous variables are more, this is a good sign indicating that "model generates interesting dynamic behavior from within the system.". If a variable appears somewhere in a feedback loop, or it is influenced by another variable that it is in a feedback loop, than the related variable is said to be endogenous variable in the model.

In addition to the bull's eye diagram, to provide a snapshot picture of the extension of the model, the major factors under consideration are grouped under four categories and presented in Table 5.1. The mentioned factors cited in Table 5.1. are explained in detail through sections 5.2.3- 5.2.19.

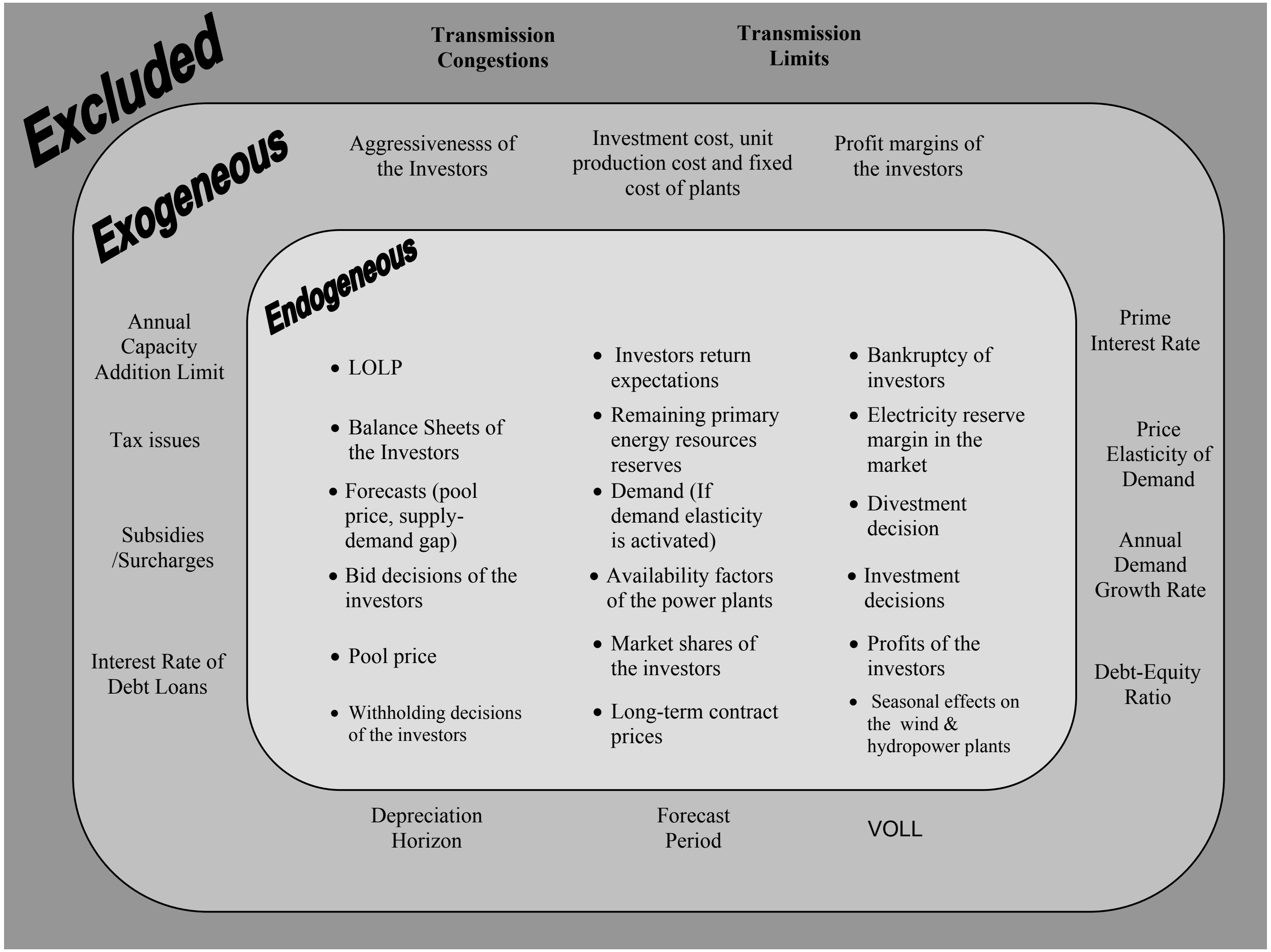


Figure 5.4. Bull's eye diagram of the model

Table 5.1. Major factors under consideration in the proposed model

INVESTOR RELATED	REGULATORY and FINANCE RELATED
• Aggression level • Capacity withholding • Long-term contracts • Profit margins • Investors' composition of initial power plant portfolio (already installed and under construction) • Length of forecast period • Capital stucture of the investors • Debt/Equity ratio in new investments	• Annual capacity addition limit • VOLL (value of loss load) • Tax rate • Cost of debt • Cost of equity • Incentives/Surcharges – Tax Exemption – State support for renewable energy – CO_2 Tax • Prime interest rate • Debt payment period
PLANT RELATED	**DEMAND RELATED**
• Seasonal effects on availability of wind and hydropower plants • Construction times • Cost estimates • Age of the power plants • Availability and capacity factors	• Annual and monthly peak demand • Hourly load curve • Price elasticity of electricity demand • LOLP (loss of load probability)

5.2.3. Players and Their Characteristics in the Model

There are up to six players in the model, which are of four types. The players in the proposed model are,

i) the incumbent (INC), which holds a major share of the current market,

ii)three Independent Power Producer Groups[5] (IPP1, IPP2, IPP3), who are generally smaller in size but are more focused and agile (regarding generator inventories, decision making and cash flows) and tend to stand and succeed in the market by competing with the incumbent,

iii) one New Entrant (NE), which may enter the market according to the market conditions.

iv) a Regulator, who oversees the market and aims to facilitate the creation of competitive conditions, while trying to ensure fair prices for the consumers.

The model-user selects his/her role at the beginning of the simulation:

[5] Independent Power Producer Groups are denoted as IPPs throughout this thesis.

1. Either he assumes one of the above stated player types (active player), and the rest of the players (passive players) are driven by the computer, or
2. He inputs all the parameters describing the market behavior; then, all the players are driven by the computer (passive players). In the model, default rules and settings are defined for each passive player.

The Incumbent exists in the market at the beginning of the model. As previously stated, it holds a major share in the market. The Incumbent has the highest capacity and highest capital among all investors. The Incumbent's main business objective is to maintain his current market share and profitability.

In the model there are 3 *Independent Power Producer (IPP)* groups. These IPPs also exist in the market at the beginning of the planning horizon. In comparison to the market share of the Incumbent, these investors have lower market shares. Their main business objective is to maintain their current market share and profitability. They have the chance to takeover divested plants of the incumbent when (because of anti-monopolistic considerations) the regulator requires the Incumbent to sell some of its power plants.

The *New Entrant (NE)* does not exist in the market at the beginning of the planning horizon. He has lower cash than the other investors. He has low (debt financing) credibility because of his low book value (fixed assets and cash). He can enter the market in two conditions; after his/her new power plants under construction are completed or by taking over the divested plants (by the regulator) of the incumbent.

There are some advantages of taking over divested plants. Since divested plants are already built and generating electricity, there is no need to wait for their construction. Additionally, as a divested plant is an already existing one, its book value is lower than that of new plant investment; so, it is cheaper to take over capacity rather than constructing new capacity.(Divestment prices are based on book values, which take asset depreciation into consideration).

The *Regulator* (a passive player in the model), oversees the market and aims to facilitate the creation of competitive conditions. Given that the Incumbent has a large market share initially, the Regulator is particularly aware of the potential abuse of this power (and possible monopolistic tendencies). The regulator orders divestment if he deems it necessary. This means that the regulator requires the Incumbent to sell some of its plants, if the supply share of the Incumbent is greater than or equal to a predetermined level. In the default setting, this level is 50 per cent (of the overall electricity supply). In the default rule, the amount of divested capacity for each plant type of incumbent (INC) is calculated via Equation 5.1.

$$\textit{The amount of divested capacity for each plant type of INC} = \textit{(INC's supply share} - 0.50)*\textit{(INC's capacity for each plant type)} \quad (5.1)$$

The generation capacity up for sale is offered to each investor on an equal opportunity basis. Investors; (the NE and the IPPs) may buy the offered part of the Incumbent's plants as much as their financial power, (cash and credit) let them. Additionally, in case of divestment, the regulator arranges loans with comparatively lower interest rates to the IPPs and the NE. This is mainly due to anti-monopolistic considerations. This is considered in the model via Equation 5.2.

$$\text{IRD} = \text{Interest Rate on Debt} + \text{Help}* \text{Max}((\text{Incumbent supply share} - 0.5),0) \quad (5.2)$$

The term "IRD" denotes interest rate on the loan offered to the NE and IPPs, if they need and seek financial support to buy divested plants of the Incumbent. The term "Help" in Equation 5.2. is a negative rate used to model the institutional or regulatory loan support to the NE, and the IPPs, when the supply share of the incumbent is seen as a strategic threat to competition. If the value of "Help" is zero, then this means that there is no discount in the interest rate on such loans.

5.2.4. The Electricity Demand Profile

Consumers and distribution companies are not explicitly modeled, but their important functions and roles in the market are reflected to the model within the framework of a detailed demand profile.

Transmission losses and reserve margin requirements are assumed to be included in the demand profile. Consequently, there is a single electricity price for the overall region, so that price differences within the region due to transmission congestion and losses are not taken into account. In the model, each day of a month is assumed similar in terms of demand characteristics, with each day being divided into nine time intervals (by categorizing successive hour slices having similar demand characteristics under the same time interval) and each interval's demand being a predetermined percentage of annual peak demand (these percentages are determined based on hourly load curves data obtained from TEIAS[6] – the Turkish Electricity Transmission Company). As examples, Figures 5.5, and 5.6 display the hourly load curves of the 3rd Wednesday of 2002, through January-June and July-December, respectively.

Annual peak demand, long-term demand elasticity and annual growth rate of demand values are assumed to be available at the beginning of the 20 year planning horizon. Additionally, if the player wants, he/she can change these values by pausing the simulation run (in the Microworld version of the model where the run is paused automatically every five years, so that active player can change the settings related with market structure and his/her decisions.) Default annual growth rate of electricity demand is seven per cent (This percentage is the average of the pessimistic and optimistic annual demand growth rate projections presented in the TEIAS web-page.)

During a simulation run, annual peak demand values are updated monthly with respect to annual peak demand growth rate. The demand for each individual time interval is a predetermined percentage of the annual peak demand as displayed in Table 5.2. The percentages in Table 5.2 are calculated by dividing the demand values of each time interval to the annual peak demand value, which are determined using Figures 5.5. and 5.6. On the other hand, in TEIAS's demand projections, it is assumed that an actual monthly demand value deviates from the projected demand ranging -5 per cent to +10 per cent. Based on this consideration, the deviation between the projected figures of monthly demand of each time interval and its realized value is assumed to be a random variable with a uniform probability distribution, ranging -5 per cent to 10 per cent of the computed expected forecast for that time interval. Realized demand in the model is calculated by Equation 5.3.

[6] The hourly load curves available at the TEIAS web-page, www.teias.gov.tr.

The term URND(-0.05, 0.1) in this equation is abbreviation for a uniformly distributed random variable, ranging -0.05 to 0.1.

Demand of a time interval of a month=Annual Peak Demand (5.3)
*(Ratio of the average demand of the related month of the related time interval to annual peak demand+URND(-0.05, 0.1))

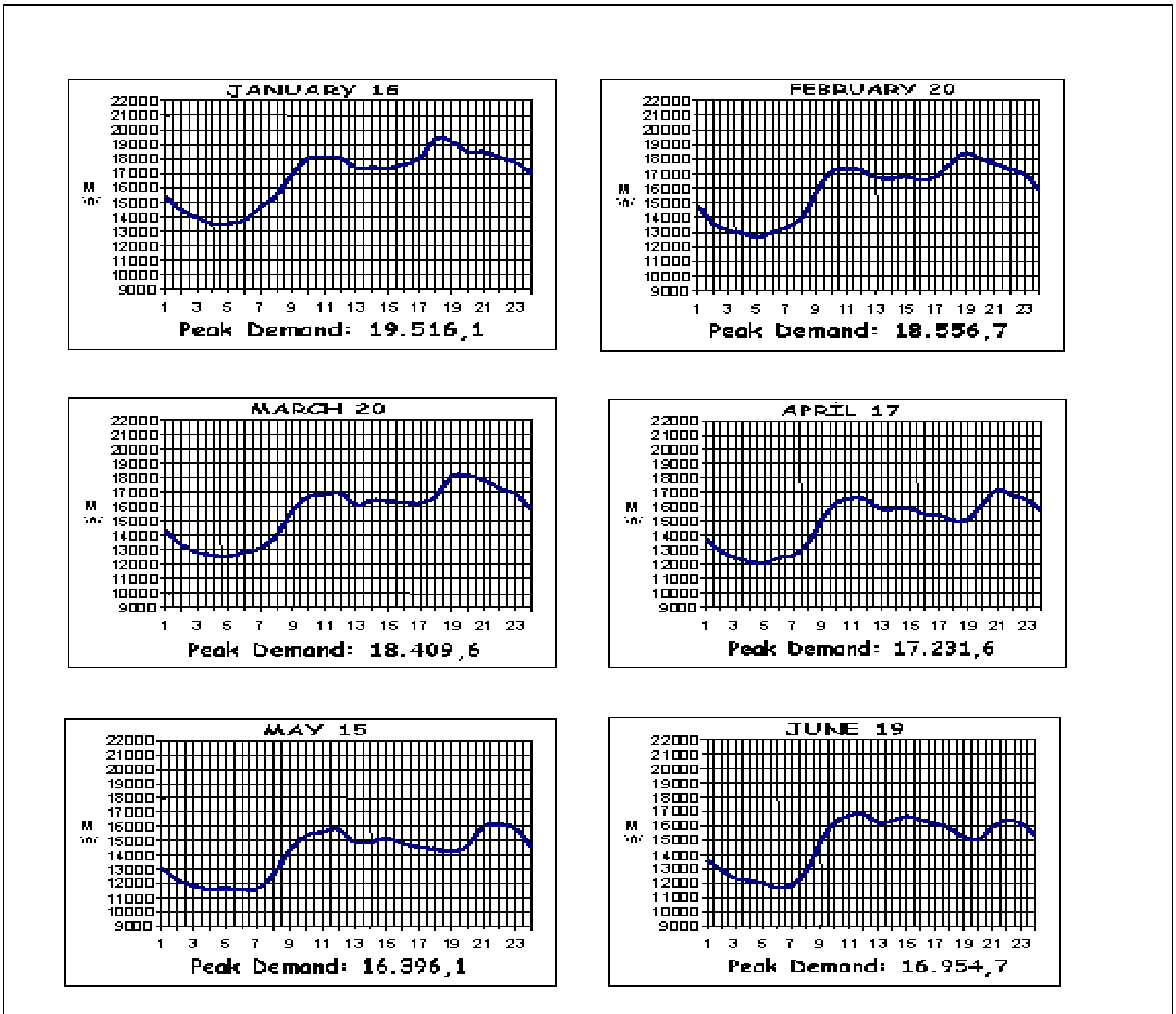


Figure 5.5. The hourly load curves of the 3rd Wednesday of January-June in 2002.

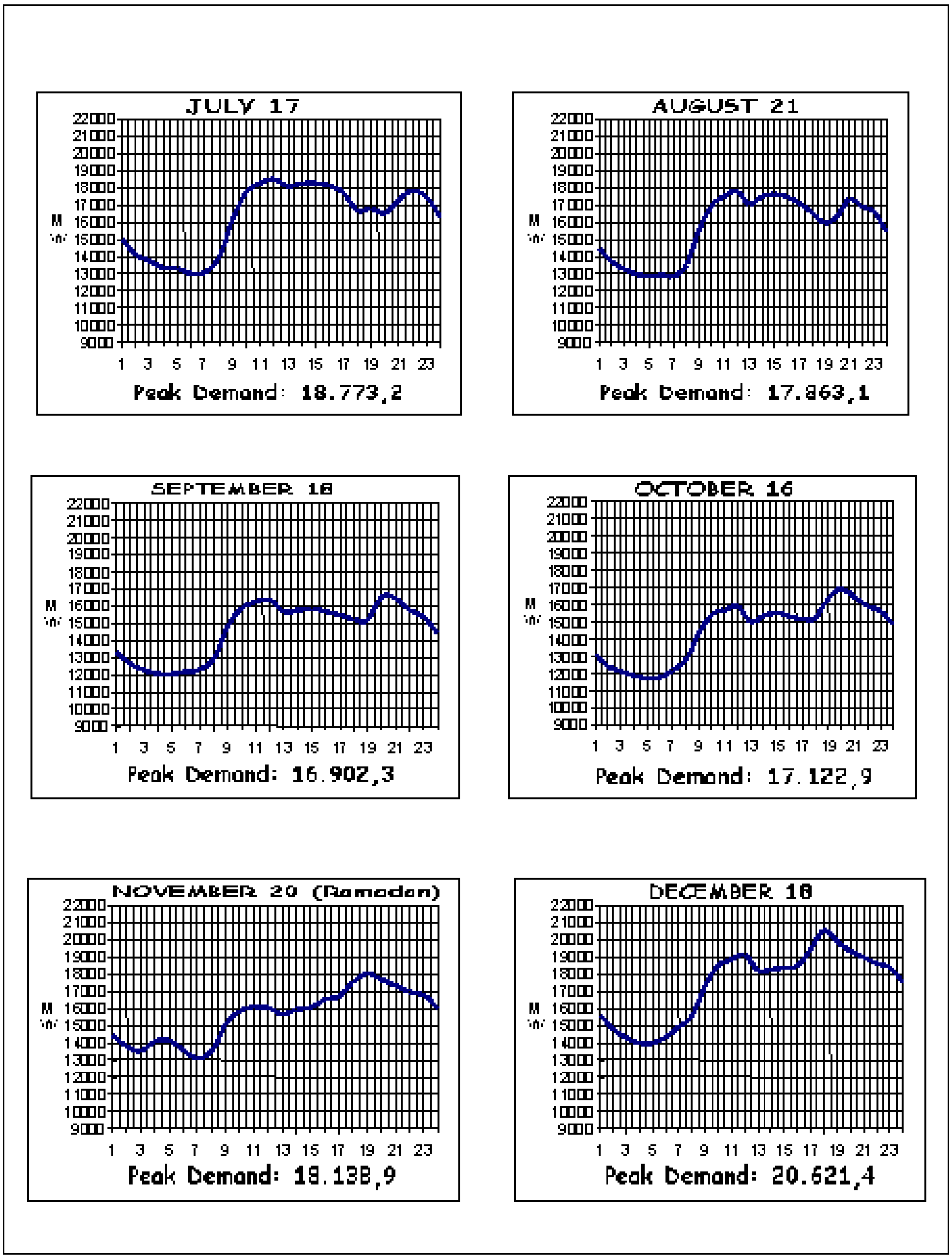


Figure 5.6. The hourly load curves of the 3rd Wednesday of July-December in 2002

Determined time intervals consist of the following time periods.

- 1st time interval consists of 1:00-3:00;
- 2nd time interval consists of 3:00-8:00;
- 3rd time interval consists of 8:00- 10:00;
- 4th time interval consists of 10:00-13:00;
- 5th time interval consists of 13:00-16:00;
- 6th time interval consists of 16:00-18:00;

- 7th time interval consists of 18:00-21:00;
- 8th time interval consists of 21:00-23:00;
- 9th time interval consists of 23:00-1:00.

Table 5.2. Ratio of average demand of each time interval to annual peak demand

Interval	Jan	Feb	Marc	April	May	June	July	Aug	Sept	Oct	Nov	Dec
1st Interval	0,76	0,74	0,68	0,68	0,64	0,65	0,73	0,68	0,64	0,61	0,68	0,73
2nd Interval	0,74	0,67	0,65	0,62	0,59	0,60	0,66	0,64	0,59	0,58	0,66	0,69
3rd Interval	0,86	0,75	0,76	0,71	0,66	0,68	0,74	0,73	0,67	0,66	0,69	0,87
4th Interval	0,92	0,89	0,85	0,83	0,79	0,83	0,90	0,85	0,79	0,76	0,78	0,91
5th Interval	0,91	0,87	0,82	0,81	0,75	0,82	0,90	0,86	0,78	0,75	0,77	0,88
6th Interval	0,90	0,86	0,82	0,78	0,74	0,82	0,89	0,85	0,77	0,74	0,81	0,93
7th Interval	1,00	0,93	0,89	0,76	0,73	0,76	0,83	0,80	0,77	0,79	0,87	0,96
8th Interval	0,94	0,89	0,88	0,85	0,80	0,80	0,87	0,84	0,78	0,78	0,83	0,91
9th Interval	0,88	0,84	0,84	0,81	0,77	0,78	0,82	0,80	0,73	0,74	0,80	0,87

In the model, long-term demand elasticity is also given due consideration: At the beginning of each year, last five years' average pool price is calculated as a reference market price and then compared with the average pool price (market price) of the previous year. If the previous year's market price is higher than the calculated reference market price, demand is further adjusted due to demand elasticity. (demand elasticity is defined as the percentage change in demand that occurs in response to a percentage change in price).

In addition to the above attributes and characteristics considered in the demand module, different load curve patterns are also offered to the model user in the microworld version of the model, to use in his scenario analysis.

5.2.5. The Power Plants

There are several power plant types in Turkey, categorized according to their primary energy resource needs. These resources play key roles on cost and availability features. In the model, each investor has the opportunity to build/own generating plants out of eight different plant types, as long as he/she has the necessary funding (either as capital and/or financing) These eight plant types are; geothermal, wind, imported hard coal, diesel oil, lignite, natural gas, small hydropower plants and large hydropower plants. However, due to technical restrictions of Stella, the overall available capacity (in MW) of each plant type (rather than the capacity of each individual plant) is considered for each investor (for building, owning, operating, depreciating and disposing).

Deciding on the plant type to be built is a strategic decision for individual investors. Decision makers have to evaluate these power plants based on their capacity and availability factors, CO_2 emissions (especially when the CO_2 tax option of the model is activated), production cost per unit (marginal cost), fixed costs, capacity costs (investment cost) and economic plant life characteristics.

The availability factor for each plant type refers to the percentage of time that a plant can be actively used, (i.e. is not out of service due to maintenance or repairs.) Besides, in the developed model, it is assumed that as power plants get older, their availability factors decrease[7]. Here, it is important to restate that the overall available capacity of each plant type (rather than the capacity of each individual plant) is considered for each investor. So, instead of the age of each individual plant, the average age of the plant types for each investor is used in the model.

The capacity factor for each plant type measures the productivity of the related plants, comparing their actual production with the amount of power the plants would have produced if they had run at full capacity for the whole year (i.e. the ratio of the average energy output of the plants to maximum potential energy output of the plants in regard to their availability.). The main reason for power plant types having less than unity capacity factors is non-availability of their primary energy resources (due to geographic and meteorological considerations in case of wind, geothermal and hyro; and import and technical limitations in case of the others).

The model is equipped with average monthly capacity factors for wind and hydropower plants. Additionally, based on the historical data of the last 30 years, the precipitation profile of Turkey is determined as 65 per cent moderately rainy, 20 per cent dry and 15 per cent very rainy. To reflect this randomness to the model, during a simulation run, at the beginning of each year, the amount of annual precipitation is

[7] It is assumed that each month, 0.05 per cent of availability factor of each plant type of each producer decreases.

randomly generated(based on these fractions) and then the realized capacity factors for hydropower plants are determined based on the randomly generated precipitation figures. Default monthly capacity factors, for wind and hydro power plants (in case a moderately rainy year) are presented in Figure 5.7. and Figure 5.8. In the model it is assumed that capacity factor of the hydro power plants are 115 per cent of the values plotted in Figure 5.7, in case a very rainy year and 70 per cent of these values in case a dry year.

If the model user does not want to consider seasonality effects on wind and hydro power plants' capacity factors, then each year throughout a planning horizon is assumed to be moderately rainy and instead of employing the monthly capacity factors presented in Figures 5.7. and 5.8., average capacity factors given in Table 5.3. are used throughout the planning horizon.

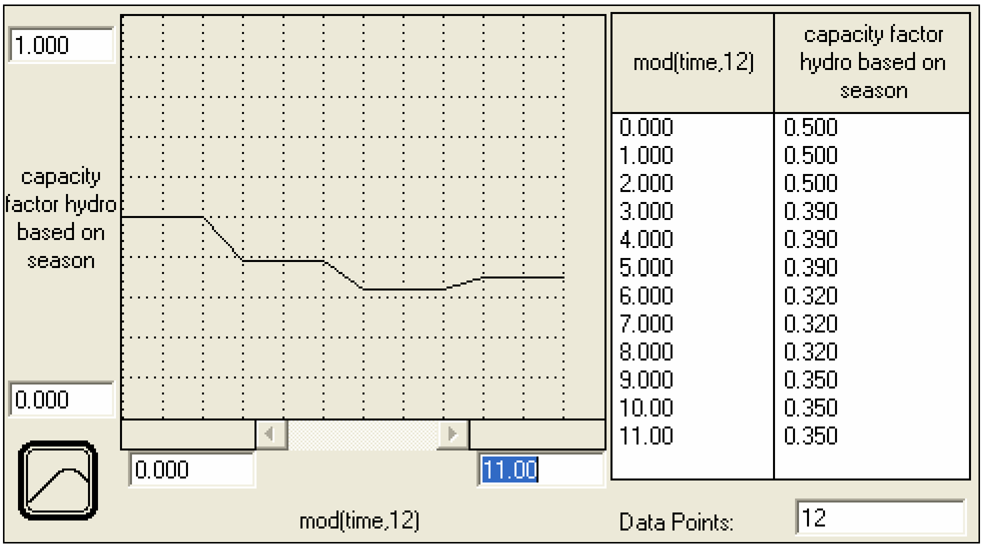


Figure 5.7. Capacity factors of hydro power plants in case a moderately rainy year

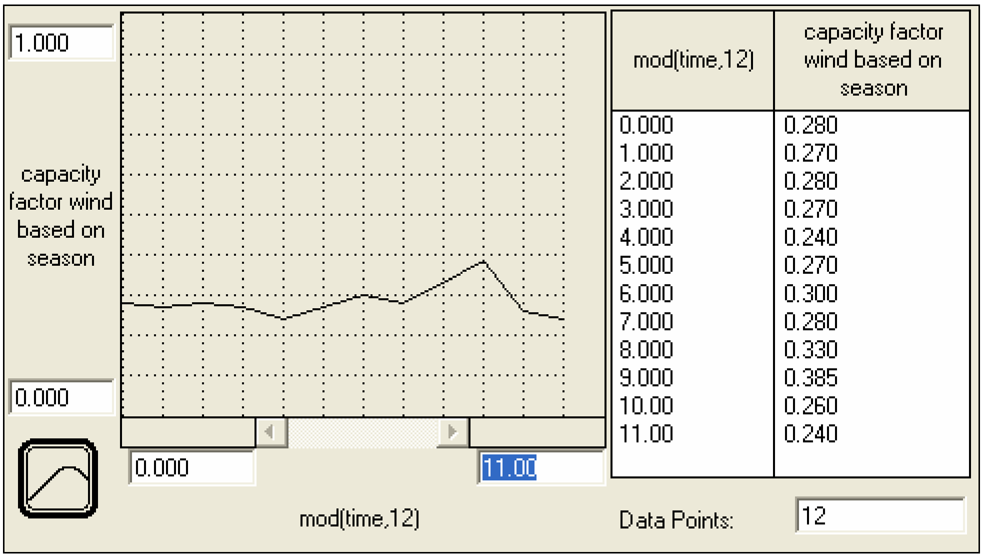


Figure 5.8. Capacity factors of wind power plants

The unit production cost ($/MWh) includes fuel cost (resource), maintenance and operating costs.

Annual Fixed costs ($/MW) include insurance costs and salaries of the plant personnel. In the default setting, based on expert opinions, for each plant type it is assumed to be one per cent of the capacity cost of the related plant type.

Capacity Cost ($/MW**)** indicates the unit investment cost. In the model, capacity cost is used to determine the value of fixed assets, depreciation costs of the investors, amount of funds required for investment (building or buying divested plants of Incumbent) and the value of the divested plants of the Incumbent.

CO_2 Emission (kg/MWh) gains importance in the presence of CO_2 tax in the market. In the default setting, it is assumed that CO_2 emission for lignite, imported-hard coal, natural gas and diesel-oil power plants are as following; 308, 308, 187, 250 kg/MWh, respectively.

Default values of the parameters discussed above are obtained from the EMO (The Chamber of the Electricity Engineers), and these values are assumed to be the same for all investors. The related data is given in Table 5.3. However, in the default setting, due to different managerial capabilities, the Incumbent's power plant construction time is assumed to be longer than the other investors' construction times. Plant construction time of each investor is defined as a percentage of the average construction time and is presented in Table 5.4. (For each plant type, percentages given in Table 5.4 are the same). Power plant construction times, presented in Table 5.3, involve two main delays, which are obtaining a permit to build a new plant and constructing it.

Table 5.3. Some key characteristics of the considered plant types in the default setting

Plant Types	Unit Production Cost ($/MWh)	Capacity Cost (1000$/MW)	Plant Life (years)	Average Construction Lead Time (months)	Average Capacity Factor (%)	Availability Factor (%)
Lignite	25	1600	30	36	0.75	0.75
Imported Hard Coal	35	1450	30	36	0.75	0.75
Diesel Oil	60	1280	30	12	0.8	0.75
NG	30	680	30	24	0.65	0.75
Geothermal	1.15	2000	30	36	0.9	0.7
Small-Hydro	0.5	750	30	48	0.5	0.92
Large-Hydro	0.5	1300	50	72	0.4	0.85
Wind	45	1350	20	12	0.25	0.90

Table 5.4. Default power plant construction times of the investors with respect to the average construction times of power plant types

Investor Type	Construction Time of the Investors w.r.t. average construction times
Incumbent	10% greater than AV
IPP3	Average Value
IPP	3% less than the average value
IPP2	5% less than the average value
NE	10% less than the average value

Construction times of power plants which are under construction throughout a simulation run are modeled as pipeline delays. Pipeline delays are used when the delay time is constant and in which the order of exit from the delay is precisely the same as the order of entry. In the model, the pipeline delay structure presented in Figure 5.9, is deployed for each power plant type of each investor. As an example, the NE's Wind Power Plant Capacity Built, (which becomes operational at the end of its construction time) is illustrated in Figure 5.9 and is mathematically defined by Equation 5.4.

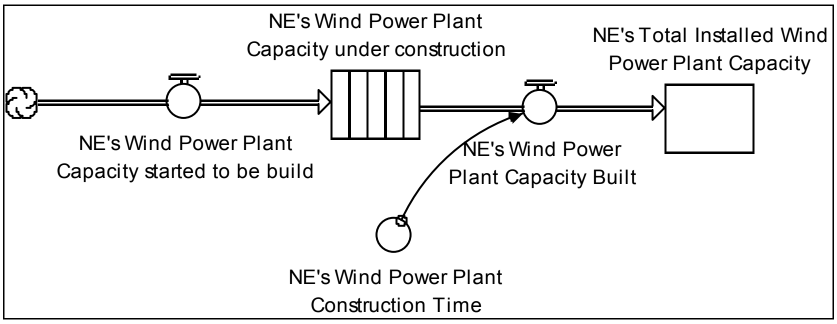


Figure 5.9. An example of pipeline delay structure implemented in the developed model

NE's Wind Power Plant Capacity Built = NE's Wind Power Plant Capacity started to be build(t- NE's Wind Power Plant Construction Time) (5.4)

On the other hand, first order delay is assumed for the construction lead time of each type of initial power plant under construction of each investor. The outflow from a first-order material delay (capacity launched to the market by completing its construction time) is always proportional to the stock of capacity of power plant under construction as defined in Equation 5.5.

Outflow = Initial capacity under construction/construction time of the related power plant type of the related investor (5.5)

5.2.6. The Power Pool

Since, the model is developed over monthly-based periods, the bidding process is also based on monthly periods and an electricity pooling system is implemented. As mentioned before, each day of a month is assumed similar in terms of demand characteristic. However, the electricity demand of each month and time interval is different from one other. Within this general framework, each month each investor submits bids to the regulator for the succeeding month.. Each bid specifies a certain time interval and offers a certain amount of electricity under a certain unit price, guided by the bidders' production capacity and production costs. (Each investor's bid prices are assumed to be sum of the weighted average of their unit production costs and targeted profit margins.) In order to satisfy the succeeding month's demand in every period, the Regulator determines the amount of the electricity to be bought from each bidder and the system marginal price for each time interval of the succeeding month. During this phase, the investors are contracted by the regulator (i.e. their bids accepted) in ascending order of price. The most expensive unit bought establishes the system marginal price (SMP), which then all contracts receive during that month for that time interval. If the generators offer the same price, the first priority is given to the NE, then to the IPPs, to encourage new entrants.

Within the general framework of the bidding and pooling system described above, the following assumptions are adopted due to the technical capabilities of the Stella Software;

- Investors offer one aggregate bid price and one aggregate supply to the pool instead of offering individual prices for each of their generating plants. This aggregate bid price is the sum of the weighted average of production costs (marginal cost) of the power plants in the portfolio of the investor and his targeted profit margin. The aggregate supply capacity, on the other hand, is defined as the total available capacity of the power plant portfolio of the investor.

- These assumptions are supported by the following reasoning regarding actual behavior tendencies of investors: the investors do not prefer to extensively exploit their most attractive plant types (cheapest in terms of production costs within their plant portfolio), but rather spread their production commitment evenly among each plant type in their portfolio. Another reason why producers prefer an even distribution is that if a plant type is not actively deployed for a long time, the experience and capabilities of its personnel, as well as its organizational and technical well being may be negatively effected.

In the liberalized electricity markets, the Regulators generally offer, an additional price mark-up (capacity charge), which is designed to provide an incentive for future investment in additional generation capacity. This mark-up is based on the VOLL (value of loss load) and the LOLP (Loss of Load Probability) (Bunn et. al, 1997). In our model this mentioned price mark-up is also implemented.

The regulator assesses and sets the value for loss of load (VOLL), which also represents the price consumers are willing to pay to avoid loss of supply. In the proposed model, VOLL is assumed to be 2000$/MWh . On the other hand, if the model user wants, he/she can change this value at the beginning of the simulation run and every five years.

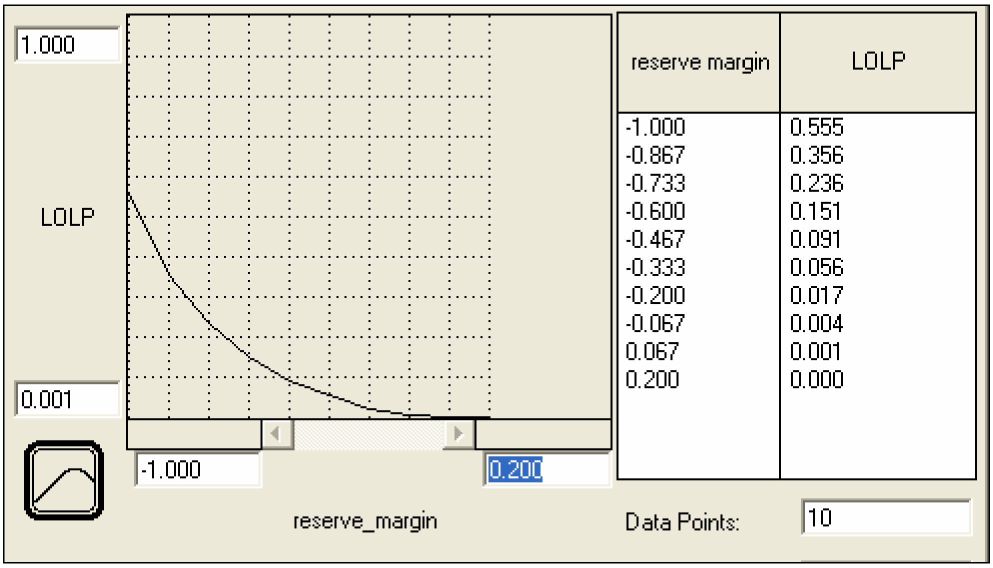
LOLP reflects the probability that electricity demand will exceed supply at a given time period and it is a function of excess capacity. Excess Capacity (i.e. reserve margin) in turn is calculated by the Equation 5.6. The term “Total Available Capacity” used in Equation 5.6. is the summation of the available capacity offered to the pool by each investor. The greater the available capacity relative to peak demand in any time interval, the lower the excess capacity in the market (as can be observed in Equation 5.6).

$$\text{Excess Capacity} = (\text{Total Available Capacity} - \text{Peak Demand})/\text{Peak Demand} \qquad (5.6)$$

The default LOLP function deployed in the simulation model is given in Figure 5.10. The model user has the opportunity to change this function at the beginning of a simulation run and every five years.

The Pool Purchase Price (PPP) paid to all producers is obtained via Equation 5.7. The second part of the summation in Equation 5.7. is the capacity charge paid to the investors. It should be mentioned that in case the SMP is equal to the VOLL, then the regulator does not pay any capacity charge to the investors. As it can be noted from Figure 5.10., the greater the reserve margin, the lower the LOLP. Therefore, the higher the reserve margin, the lower the capacity charge per MWh paid to the investors.

$$PPP = SMP + LOLP * max\,((VOLL - SMP),\ 0) \qquad (5.7)$$



reserve margin	LOLP
-1.000	0.555
-0.867	0.356
-0.733	0.236
-0.600	0.151
-0.467	0.091
-0.333	0.056
-0.200	0.017
-0.067	0.004
0.067	0.001
0.200	0.000

Figure 5.10. The default LOLP function used in the model

5.2.7. Incentives

As previously mentioned in 5.2.2., in case of divestment, if the market share of the incumbent is more than a predetermined level, low cost loans (in other words, discounted loans) are made available for the IPPs and the NE as an additional incentive. (Capacity payments based on VOLL and LOLP can be considered as another indirect incentive to all investors).

In the EU countries it is aimed that by 2010, 22 per cent of the energy generated will be produced by renewable resources. In line with this EU aim, two renewable energy power plants (REPP) incentive options are implemented in the simulation model: These are; government subsidy loans and extra tax exemptions.

Besides the investment incentive offered for the REPP, there is also an additional CO_2 tax for thermal power plants (natural gas, hard coal, diesel oil and lignite type of power plants).

The Incentive for the REPP and the exercise of the CO_2 tax are left optional in the model (i.e. to be activated by the model-user if so desired)

5.2.8. Profit Margins

Expected profit margins of all investors are inputted to the model by the investors at the beginning of the 20 year planning horizon and then can be updated (every five years) during the simulation run.

Due to the mechanics of SD and Stella Software, profit margins are not calculated within the system; in other words, price optimization is out of the scope of this model. (i.e. Profit margins of the producers are exogenous variables)

5.2.9. Taxation

Taxation is another issue given consideration in the model. If not set otherwise at the beginning of a simulation run, the tax rate is fixed to 20 per cent by default. Tax is calculated for net earnings, that is after fixed costs, variable costs, interest costs and depreciation costs are subtracted from gross earnings. (The method deployed for depreciation is linear for a period of 20 years.)

On the other hand, a tax exemption option is available. According to the present relevant legislation in Turkey, regarding energy sector investments, 40 per cent of fixed asset investments may be deducted from the pre-tax profit (which means that no tax is incurred until cumulative pre-tax profit gets more than 40 per cent of the new investment). The implementation of the mentioned tax exemption is left optional in the model (i.e. to be activated by the game setter).

5.2.10. Behavior of Power Companies in the Market

In the model, three different levels of business risk preference are made available to the investors. These levels are described as; Aggressive, Neutral and Conservative. It is assumed that as investors get more aggressive, their rate of return expectation from a new investment and their profit margins decrease, accordingly, their willingness to build new power plants (at less expected profit and therefore at increased risk) increases.

5.2.11. Long-Term Contracts

Most liberalized energy market implementations allow for private long-term contracts between the generators and large consumers, which bypass the pooling/bidding mechanisms. Such long-term contracts can optionally be included in the model. If no long-term contracts are allowed, this means that pure pooling mechanism over all electricity sales prevails (This is the case in the default setting). The game-setter may change this option on the model interface and include long-term contract options in the system. In this case, the active producer is asked to define the portion of his/hers capacity that he/she wishes to be allocated to long-term contracts (which means confirmed sales, but usually at a discounted price). The available options are 15 per cent, 10 per cent, 5 per cent, 0 per cent.

A reference value for the long term contract price is determined based on the average price of the last five years. Long-term contract price for the first five years, on the other hand, may be input by the player at the beginning of the planning horizon (the default value of which is assumed to be 80 \$/MWh, current average electricity prices in the market in Turkey).

The portions of passive investors' capacities that are to be allocated to long-term contracts vary depending on their aggression level. Similarly, contract prices of the passive investors also depend on their aggression level. Aggressive investors are assumed to take more risks and as such be willing to have less long-term contracts, compared to more conservative investors.

As the number of long-term contracts in the market increases, the price of the next contract is assumed to be more competitive (i.e. lower). If long term contract option is activated, long term contract price changes for passive investors, are illustrated in Table 5.5.

Table 5.5. The relationship between long-term contract price, aggressiveness level and long term contract commitments of passive investors

Behavior Type	Per cent Capacity Allocated to Long Term Contracts	Contract Price ($/MWh)
Aggressive	5	(1-0.05) x last 5 years market price
Neutral	10	(1-0.10) x last 5 years market price
Conservative	15	(1-0.15) x last 5 years market price

5.2.12. Reserve & Capacity Addition Limits

Deployment of electricity generation alternatives is limited with resource availability and reserves. Total available (proven) reserves can be inputted by the game-setter at the beginning of the simulation run and/or updated every five years.

In the model, primary energy resource reserve is defined as the total potential capacity of new plants that may be constructed until the country's reserve or access to the necessary primary energy resource is totally exploited. Take the following case as an example: if the wind reserve of the country is expressed as 20.000 MW, it simply means that the total installed capacity of wind plants in the country can reach only 20.000 MW at its maximum. It should be noted here that the reserve is expressed in MW instead of various other units, for the sake of simplicity in calculations.

Besides the reserve limits, the game setter may decide whether or not to have an annual capacity addition limit (additional capacity per technology per year) during the planning horizon. If it is decided to have such limits, the values given by TEIAS are used (i.e. up to 1500 MW of new hydropower, 500 MW of new small hydropower, 125 MW of new wind plants are assumed to be achievable annually).

Reserve and capacity addition limits are distributed among (offered to) the investors on an equal basis to ensure competition in the market.

5.2.13. Withholding

"Withholding" is defined as an investor deliberately reducing his/her available electricity supply, in order to increase the market price. In the developed model, the game-setter may choose to have such a withholding option in the simulation run or not (in the default setting, it is not included).

When the withholding option is activated, any investor whose capacity exceeds 40 per cent of total productive capacity in the market, may withhold 25 per cent of his capacity (excluding long-term contract requirements). Note that the mentioned default rule applies to passive investors; an active investor has always a chance to withhold his/her generation capacity any time and as much as he/she desires.)

5.2.14. Capital Budgeting

Since, power plant investments are highly capital intensive, the required capital is generated as a combination of debt and equity. Default debt-equity ratio in capital budgeting of new investments is three (based on the suggestions of some professionals in the market) but can be set to any other value at the beginning of the planning horizon or during the simulation run (at the five year pauses). The rationale behind this considerably high ratio is the following :

- Because of the highly turbulence-prone macroeconomic dynamics of Turkey, investors usually prefer to maintain a high level of liquidity.
- Debt financing is less expensive than equity financing because of tax exemptions associated with the financial costs (interest payments of debt).

Based on experts' opinions, the credibility (debt servicing capability) of a company, on the other hand, is defined as a function of the book value, the previous period's book rate of return (ratio of annual profit to book value of asset), the average of the past years' book rate of return and the current credit burden (debt load) of that investor. The payment period of loans is assumed to be 10 years by default, but can be reset by the LEMM user at the beginning of the planning horizon and/or every five years. As a rule, principle amounts of loans and the accrued interests are paid back in constant monthly installments.

The maximum amount of new loan that the investor can undertake is assumed to be investor's book value minus total debt load of the investor. This is named as investor's credibility and is defined as in Equation 5.8.

$$\begin{gathered} \textit{Credibility} = \min(\max((0{,}4 + \textit{past years' book rate of return} + \\ \textit{last year's book rate of return}), 0, 1) \times \max((\textit{investor's book value} - \textit{investor's} \\ \textit{total credit debt}), 0) \end{gathered} \tag{5.8}$$

The terms in Equation 5.8 are explained below:

a) Investors' Book Value: In the model, the book value of each investor (IPP1, IPP2, IPP3, NE and Incumbent) is calculated as the total liquid assets (cash) of the investor plus the investment/capital cost of his plants, minus the associated accumulated depreciation, plus accrued capital cost of investor's plants under construction.

- Total Liquid Assets of the Investor: At the beginning of the planning horizon, each investor has liquid funds at hand, the amount of which is either the default value (10^{10} \$ for NE, 10^{11} \$ for IPP1 and IPP2, $2*10^{11}$ \$ for IPP3 and $5*10^{11}$ for INC) or set by the LEMM user. Liquid assets are assumed to grow at the general annual interest rate used in the model. Equity financing of new investments is realized by fixed monthly payments during the whole construction period of the related facilities.

- Value of a Power Plant after Depreciation: The value of a power plant is calculated by deducting its accumulated depreciation from its investment costs.

- Value of a Power Plant Under Construction: The current value of a power plant under construction is assumed to be the value of the part of that plant which is already been completed, (for example, if the whole construction period of a plant is five years, one year after the start of construction, its value is assumed to be 1/5 of its total investment costs).

b) Investor's Total Credit Debt: The sum of the remaining loan installments to be paid (principal and interest).

c) Investor's Previous Year's Book Rate of Return: The previous year's return on book value. (Return on book value is the ratio of total gross revenue to the book value).

d) Investor's Past Years' Book Rate of Return: Average of individual all past years' book rate of return calculated throughout the simulation run.

Additionally, it is assumed that the willingness of investors for using debt financing depends on their aggression level. Accordingly, when determining the size of passive investors' new investments (both for puchasing divested plants of the Incumbent and in constructing new power plants), conservative, neutral and aggressive investors are assumed not to use more than 20 per cent, 40 per cent and 60 per cent of their credibility respectively, at any year.

5.2.15. Bankruptcy

As explained in Section 5.2.14, investors prefer to finance new investments by a combination of debt and equity. Debt loans are paid back in constant monthly installments.

An investor can use new loans for paying installments of already existing loans. If the liquid funds plus the credibility of an investor is not sufficient for paying loan installments, that investor is said to became bankrupt. If an investor goes to bankruptcy, a message informing the bankruptcy is posted on the interface of the LEMM. If the active investor goes to bankruptcy, the game stops.

5.2.16. Investment Decisions of Active Investors

An active investor can define his/her investment strategy using the interface of the LEMM, by setting the annual capacity expansion rate of new investment and its composition in terms of power plant types.

The model provides decision support to the active investor with many tables and charts in the Stella environment, which comprehensively reflect the behavior and conditions of the market. As the consequences of active investors' decisions are totally up to himself, no feasibility check, in terms of profitability, is applied on such decisions. A decision of the active investor is, however, checked regarding the affordability of the investment in terms of potential cash flow requirements and country's primary energy resources' reserve constraints. If the investment can not be realized completely due to cash flow requirements or primary energy resources' reserves limitations, it is partially undertaken (as much as it can be afforded by the investor and the country's primary energy resources' reserve let).

5.2.17. Investment Decisions of Passive Investors

At the beginning of a simulation run, the forecast period is asked to the model-user, which is then used in estimating the near future demand-supply gap in the market. The period may be between 0-60 months, and once fixed, it is applied for all passive investors. Demand-supply gap within the next forecast period is determined based on the future peak demand, existing capacity, potential retirements and capacity under construction. It is assumed that, at the beginning of each year, all passive investors evaluate the current situation in the market and their relative position within the forecast period. If there is a demand-supply gap within the next forecast period, and the sum of the variable cost (unit production cost) of a power plant type and investor's profit margin is greater than last year's average pool price, then feasibility of constructing the related power plant is determined based on the NPV (net present value) of the future cash flows (which depend on expected market price).

As previously mentioned, the system marginal price is determined by the marginal costs (unit production costs) of power plants in the market. Therefore, the composition of power plant portfolio of the market directly influences the market price. This effect is reflected to the expected pool price by means of the weighted average of the marginal costs of the expected power plant portfolio to be realized in the market at the end of the forecast period. As a consequence, the expected market price is determined based on simple trend extrapolation of the pool price within the forecast period and the weighted average of the unit production costs of the existing and to be operational power plants within the forecast period (In fact, it is the arithmetic average of the first and second terms).

The discount rate used in the NPV analysis for different types of power plants, is the weighted-average cost of capital. The time span used in the NPV, is the economic life of the plant type under consideration. Weighted average cost of capital (WACC) is calculated as displayed in Equation 5.9.

$$WACC = \left[\frac{debt}{investment} \times (1 - taxrate) \times r_{debt} \right] + \frac{equity}{investment} \times r_{equity} \tag{5.9}$$

The rate of return expectations of passive investors vary according to the investor type and the designated aggression level (the amount of risk the investors want to takeover decreases as their aggression level decreases). As mentioned, it is assumed that aggressive investors expect lower rates of return than conservative investors. On the other hand, a New Entrant expects the highest rate of return, whereas the Incumbent expects the lowest one. Because of this reason, by differentiating r_e (cost of equity), different discount rates for different investors are used in the NPV analysis.

Besides, cost of equity increases as the debt-equity ratio for new investments increases. Data, correlating the variation of cost of equity with regard to debt-equity ratio, is obtained from experts in the finance sector. The model determines the cost of equity considering the investor's debt-equity ratio and base cost of equity (the cost of equity in case of zero debt level) via a built-in function in the model. As such, the model user just enters his debt-equity ratio and the base cost of equity to be used for new investments. The default values of cost of equity and debt are as follows:

- cost of equity (r_e) is 11.5 per cent (in case debt-equity ratio is zero);
- cost of debt (r_d) is seven per cent.

Assumptions of the NPV analysis:

- In the NPV analysis, after-tax earnings are used as monthly cash inflows.
- All loans are paid back in monthly installments and (if not otherwise set at the beginning of the planning horizon) payment period of all loans is fixed as 10 years

by default.

- Equity financed portion of every investment flows out in constant installments during whole construction period.
- In the model, it is assumed that passive investors' investment amount (MW) depends on the expected supply-demand gap. On the other hand, expected supply-demand gap is calculated based on the projected annual peak demand. However, as it can be observed from Figures 5.5. and 5.6., the ratio of the annual average load to annual peak load is 0.76. As a consequence, through the NPV analysis for passive investors, it is assumed that expected amount of electricity that a passive investor can sell throughout a year is 76 per cent of his productive capacity.
- The NPV calculation is based on one MW capacity of the plant type under consideration.
- If the NPV of an investment option is negative, then that investment does not launch.

If the NPV of cash flows is positive, the amount of the investment is determined by the size of the supply-demand gap, the aggression level of the investors involved and reserve availability of each primary energy alternative.

The passive investors are assumed not to invest on a single type of power plant (the one having the maximum NPV among all power plant types), but prefer diversity. This assumption is based on several reasons;

a) In the liberalized electricity market, future revenue streams are no longer guarantied through regulated tariffs, since future prices of energy yet to be sold is uncertain. As previously mentioned, electricity market price is sensitive to the composition of plant portfolio of all power generators. Furthermore, the ability of individual investors to sell energy depends upon their dynamic (i.e. for each interval) cost competitiveness relative to their competitors.

b) As imported hard coal, natural gas and diesel oil, are mainly supplied by foreign countries, it is not easy to attain sustainable availability and price stability for these primary energy resources. In case of a crisis, there is high risk for producers, dependent on these resources, of not being able to sell their production under price pressure of their competitors (which may be independent of that fuel types). The availability of hydropower and wind plants, on the other hand, is highly dependant on seasonal variations. In other words, irrespective of plant type, either renewable or thermal, investors face different levels of risk perceptions and realizations.

c) In addition to the above stated arguments, if the investors concentrate only on one type of power plant (i.e. natural gas, hard coal etc.), fuel cost of that power plant may exhibit additional increases due to the escalating demand of the related fuel.

d) Accordingly, the capacity expansions of passive investors are distributed among different power plant types, (which have positive NPV), according to the ratio given in Equation 5.10., where k is the number of power plant types with positive NPV.

$$\frac{\dfrac{NPV_i}{Investment\ \ Cost_i}}{\sum_{i=1}^{k}\dfrac{NPV_i}{Investment\ \ Cost_i}} \tag{5.10}$$

The nominator in Equation 5.10. is the investment rate of return for each type of power plant, whose rate of return is more than or equal to WACC. In other words, passive investors invest in multiple plant types with percentage investment in a particular plant type being proportional to that plant type’s financial attractiveness (i.e. rate of return).

If the distribution percentages calculated above cannot be applied because of reserve and/or capacity addition limits of some plant types, the unmet investment demand is distributed among the plant types with sufficient reserves and appropriate capacity addition status, through the ratio given in Equation 5.11, where n is number of plant types with positive NPV and sufficient reserve.

$$\frac{\dfrac{NPV_i}{Investment\ \ Cost_i}}{\sum_{i=1}^{n}\dfrac{NPV_i}{Investment\ \ Cost_i}} \tag{5.11}$$

Finally, it should be mentioned that all investors are assumed to make their investment decision on January every year. The flow chart summarizing the main milestones of investment decisions of passive investors is given in Figure 5.11.

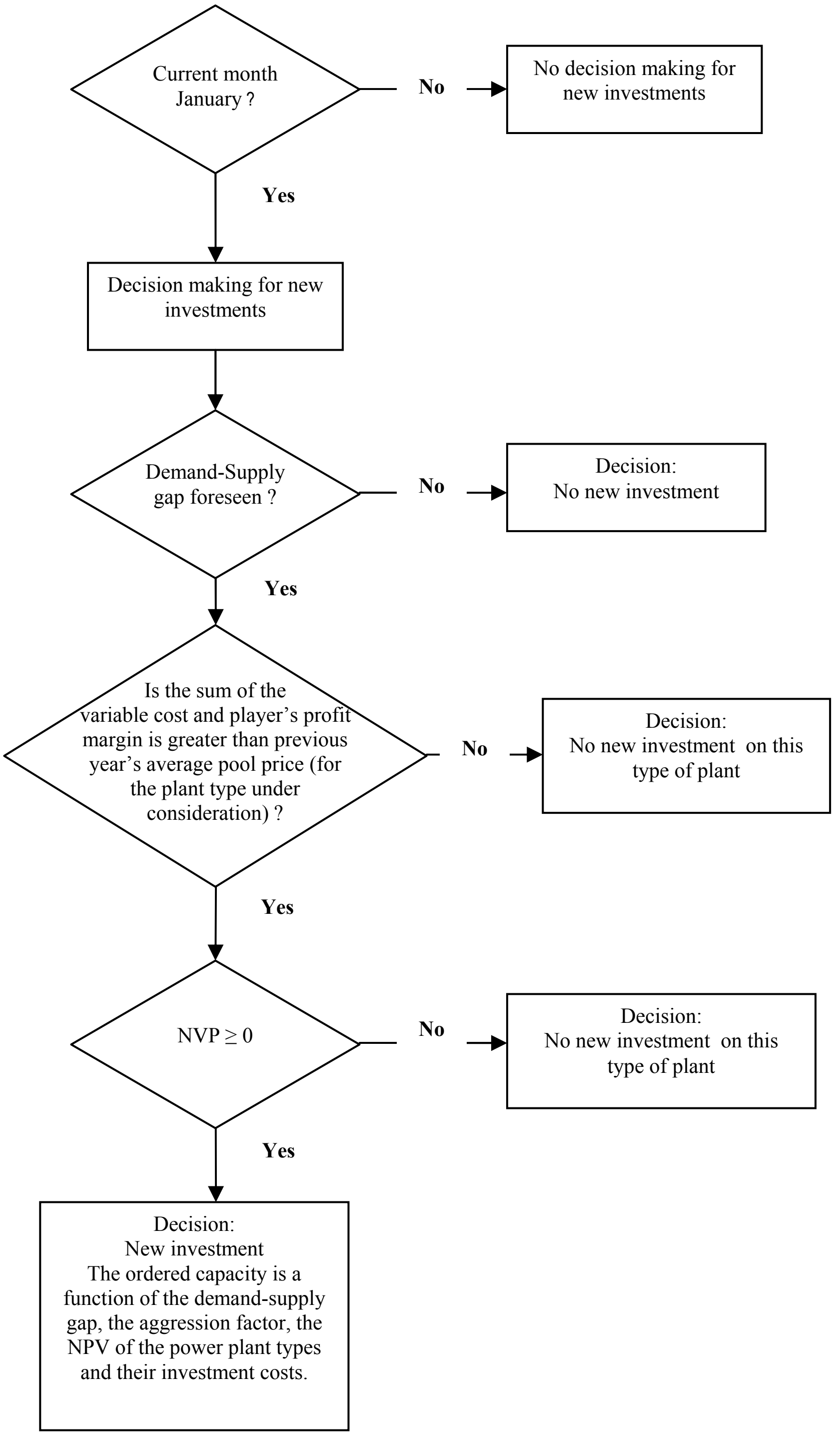


Figure 5.11. The main milestones of investment decisions of passive players

To sum up, a graphical illustration of main factors influencing investment decision of a passive investor is given in Figure 5.12. Besides, for the sake of simplification, major feedback loops related with investment decisions are presented in Figure 5.13.

In both of Figure 5.12, 5.13;

- The signs on the arrows indicate how the variables are related.
- Red arrow activates when demand elasticity is non zero.
- An arrow with a perpendicular bar indicates plant construction lead time.

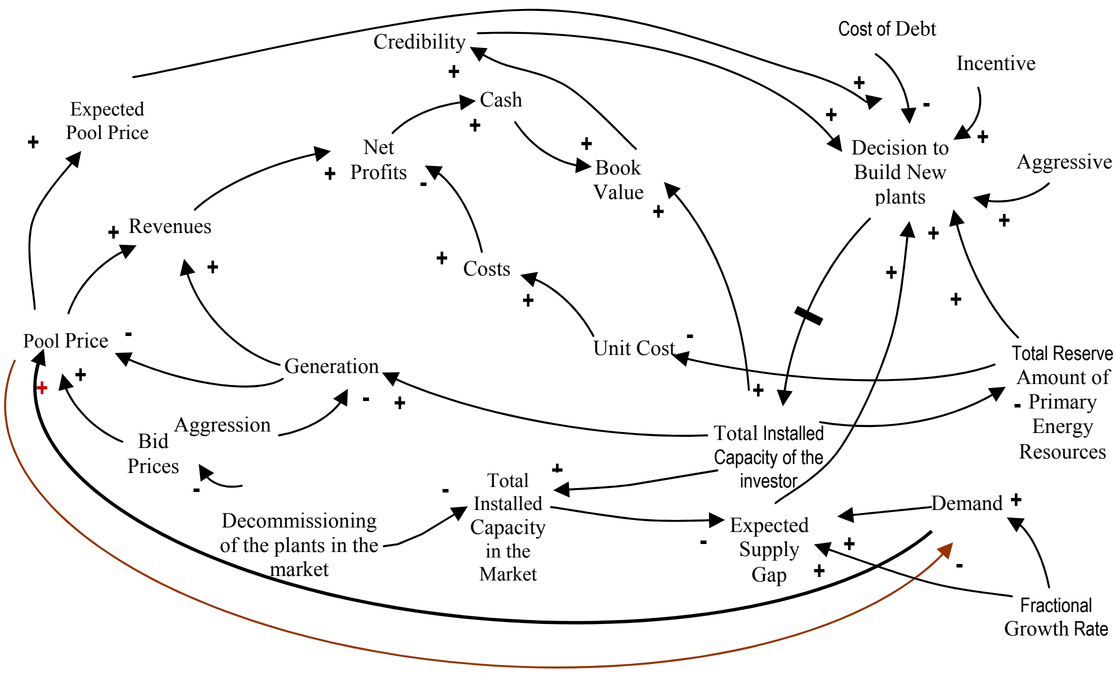


Figure 5.12. Major factors influencing investment decisions of passive investors

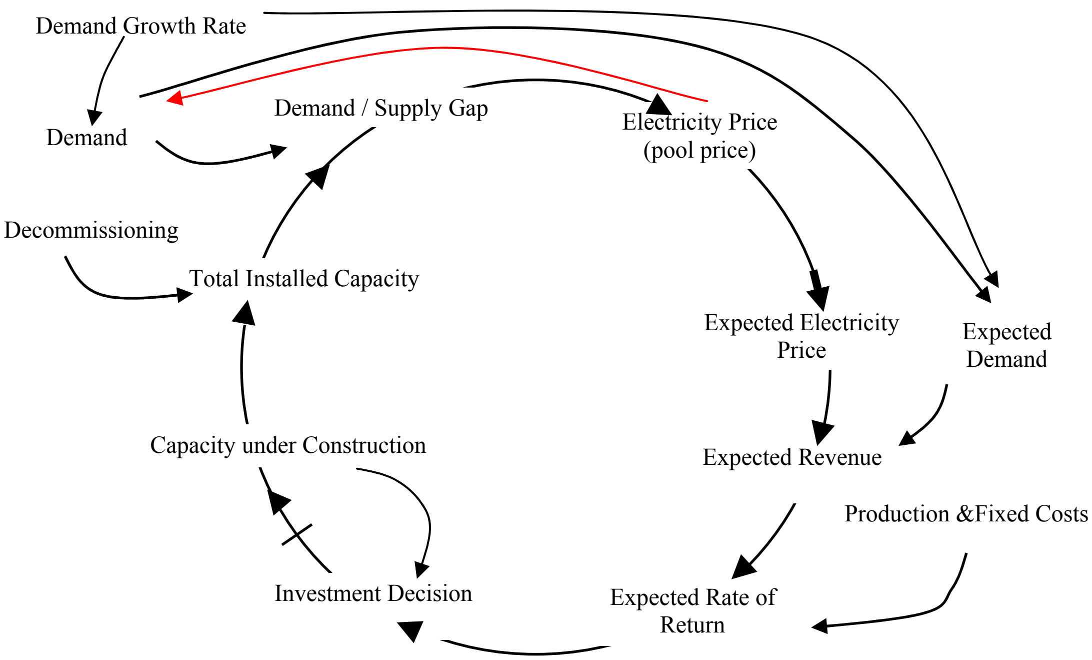


Figure 5.13. The main causal loop diagram of investment decisions

5.2.18. The Interaction and Data Flow Between the Sector Groups of the Model

The interaction and data flow between the sector groups of the model, used to group together functionally related chunks of model structure, is shown in Figure 5.14. The abbreviations, used in Figure 5.14, are given below;

- EP stands for the term “each producer”;
- ETI stands for the term “each time interval”;
- EPPT stands for the term “each power plant type”.

For the sake of simplification, sectors are grouped in Figure 5.14. These sector groups are briefly explained below:

- The Forecast Sector Group consists of two sectors which determine the expected pool price and the expected demand-supply gap.
- The Primary Energy Alternatives Reserve and Capacity Addition Limit Sector Group includes two sectors which calculate, determine, monitor and update the reserves of primary energy resources and the annual capacity addition limit.
- The Divestment Capability Sector Group determines the amount of divested

capacity of incumbent's plants which can be bought by each investor (the NE and the IPPs). There are four sectors in this group representing each IPP and the NE.

- The Plant Sector envelopes the computations and updating associated with the following parameters for all of the eight plants types
  - CO_2 emissions,
  - Fixed cost;
  - Unit production cost;
  - Construction time;
  - Capacity cost (investment cost);
  - Plant life;
  - Availability factor;
  - Seasonal variation of wind and hydropower plants
- The Profit Sector calculates the monthly revenue, before tax profit, average and current book rate of return for each investor.
- The Age Sector calculates the average age for each plant type for each investor. Average age is then used when determining:
  - Availability factor of plants;
  - Depreciation and decommissioning of plants;
  - Sales price of the Incumbent's divested plants;
- The Tax and Depreciation Sector Group consists of five sectors, each representing one producer. These sectors calculate the depreciation of the existing plant portfolio and the tax payments. The following assumptions are adopted for the calculations in these sectors:
  - Average age of plant types is used when calculating the depreciation of the plants which are present at the beginning of the planning horizon and of the ones which are acquired from the incumbent through divestment. For the depreciation of plants which become operational during the simulation run, individual plant ages are used.
  - The period for depreciation is assumed to be 20 years by default; however it can be reset at the beginning of the planning horizon or every five years by the LEMM user.

To sum up, this group of sectors calculate the profit after tax, the tax incurred and tax exemption issues and the amount of depreciation for each investor.

- The Withholding Sector Group is activated only when the withholding option is selected at the beginning of the simulation run. This sector group includes five sectors representing each investor type and describes the portion of their available capacities that will be withheld.
- The Asset Sector Group includes five sectors representing each investor type and calculates the following items for each:
  - Total cash at hand;
  - Monthly installment payments (of loans and the accrued interests)
  - Book value;
  - Credibility;
  - Interest rate for new loans (for new investments).
- The Credit Sector Group consists of five sectors representing each investor type and deals with the following operations:
  - Calculation of monthly installment payments;
  - Calculation of total debt load;
  - Monitoring bankruptcy and informing LEMM user in case of bankruptcy with a message on the screen.
- The Decommissioning Sector Group consists of five sectors representing each investor type and deals with disposing power plants off at the end of their economic life.
- The Demand Sector is responsible for
  - The calculation of the monthly demand, for each time interval, using the hourly load curves and the annual peak demand values.
  - the updating of the annual demand increase rate and the annual peak demand, according to the inputs from the Demand Elasticity Sector.
- The Demand Elasticity Sector determines the change in the demand increase rate as a function of the price increase rate. The details of this relationship is explained in Section 5.2.4.
- The Long-term Contract Sector Group consists of five sectors representing each investor type. The group becomes operational only if it is activated at the beginning

of the game by the LEMM user. The group deals with the portion of investors' available capacities tied with long-term contracts and the prices of these contracts.

- The Pool Sector Group includes nine sectors for each of nine time intervals defined in the model. The group determines the system marginal price and the amount of electricity each investor will produce, owing to their bid prices, the electricity demand of the related time interval and the electricity sale committements approved by the regulator.
- The Pool Price Sector includes nine sectors for each of the nine time intervals defined in the model and calculates the pool purchase price for each time interval based on the LOLP, the SMP and the VOLL, principles explained in Section 5.2.6.
- The Bid Sector Group consists of five sectors representing each investor type. The investors' bid prices and available capacities are determined in these sectors. The amount of electricity each investor can offer to the pool is calculated by deducting the total amount of his long-term contract commitments and his withholdings from the available capacity.
- The Total Installed Capacity and Capacity under Construction Sector Group constitutes of five sectors, each representing an investor type. Each sector includes the existing plants and plants under construction of an investor. Plants under construction become operational at the end of their predetermined construction times (pipeline delay are deployed).
- The Producers Behavior Sector defines the aggressiveness level of passive and active investors, which can be reset using the LEMM interface every five years. As such, the active investor may change his and his competitors' aggressiveness levels and evaluate the consequences of his policy and strategies.
- The Total Available Capacity Sector Group defines the amount of each investor's production at each time interval for each plant type and total available capacity in the market by considering;
  - Age of plants;
  - Annual and seasonal wind and precipitation realizations (for wind and hydropower plants);
  - Availability and capacity factors;
  - Installed capacity.

- The Regulator Sector Group takes divestment decisions and calculates LOLP for each time interval considering the electricity reserve margin in the market.
- The Passive Investors' Investment Decision Sector Group conducts NPV based feasibility checks for passive investors, for each plant type, and distributes the total planned capacity to be build among feasible power plants, as explained in Section 5.2.17. This sector group consists of five sectors representing each investor type. Investment decision of passive investors depend on;
    - Aggressiveness of the passive investor;
    - Debt-equity ratio of the passive investor;
    - Cost of equity of the passive investor;
    - Cost of debt of the passive investor;
    - Interest rate of the passive investor;
    - Tax issues;
    - Subsides/surcharges;
    - Cost data of plant types (investment cost, unit production cost, fixed cost);
    - Availability factor of the related plant type;
    - Expected pool price and expected supply-demand gap;
    - Country's primary energy resource reserve;
    - Annual capacity addition limit of power plant types;
    - Investors' bid price;
    - Economic life of the plant;
    - Credibility and cash amount of the investor.
- The Monetary Sector is concerned with interest rates and cost of equity related items.

5.2.19. Subsystem Diagram of the Model

Subsystem diagram of the LEMM is presented in Figure 5.15. Subsystem diagrams convey information on the boundary and level of aggregation in the model by showing the number and type of different organizations or agents represented. They also communicate information about the endogenous and exogenous variables (Sterman, 2000).

5.2.20. The Developed Model versus the SD Models in the Literature

The items and attributes listed below highlight the major differences between the developed SDM and the SDM in the literature, presented in Chapter 3.

- Availability of many types of power plant alternatives: In the developed model eight different types of power plants are included, whereas in the SD models reviewed in Chapter 3, a limited number of power plant types (generally natural gas, hydro, wind power plants) are considered.
- Age of power plants: In this model, age of the operational power plants are reflected to their availability factors, whereas in the SD models presented in Chapter 3, age of the power plant types are not considered.
- Use of detailed load curves: In the developed model, demand side of the market is considered in detail. Hourly and monthly demand variations are reflected; additionally, price elasticity of electricity can be deployed on an optional basis.
- Seasonal effects: A stochastic representation of hydro resource availability based on historic meteorological data is implemented. Besides, seasonal effects on wind and hydro power plants are reflected, via monthly capacity factors of such power plants.
- Availability of many financial factors and a detailed financial analysis: One of the most distinctive differences between the current model and the ones referred to in the literature is the detailed consideration and analysis of the investor and market related financial factors in this one. Investors' credibility, investors' book values, investors' bankruptcy situations, debt/equity ratio in the new investments, investors' balance sheets, investor/investment specific interest rates, tax issues, cost of equity, cost of debt are the key concepts in this regard.
- Withholding: In the developed model, in case the related module is activated, investors may withhold a portion of their capacity to force an increase in the market price of electricity.
- Annual capacity addition limits for plant types: Annual capacity addition limits may be deployed in the scenario analysis on an optional basis.

- Incentives and surcharges: In this model, various types of incentives and surcharges (such as tax exemption, state support for renewable energy and CO_2 tax) are available, while their rates and other parameters can easily be set by the users.
- Extensive diversification of investors' characteristics: In the developed model, there are five different investor types, differentiating from each other in terms of their initial financial status and power plant portfolio, their required rate of return, their willingness to build new power plants, their aggressiveness.
- Simultaneous consideration of a pooling mechanism and long-term contracts: Although there is a power pooling system at the heart of the developed model, independent pair wise electricity trade agreements can also be deployed through an optionally activated long-term contract module.

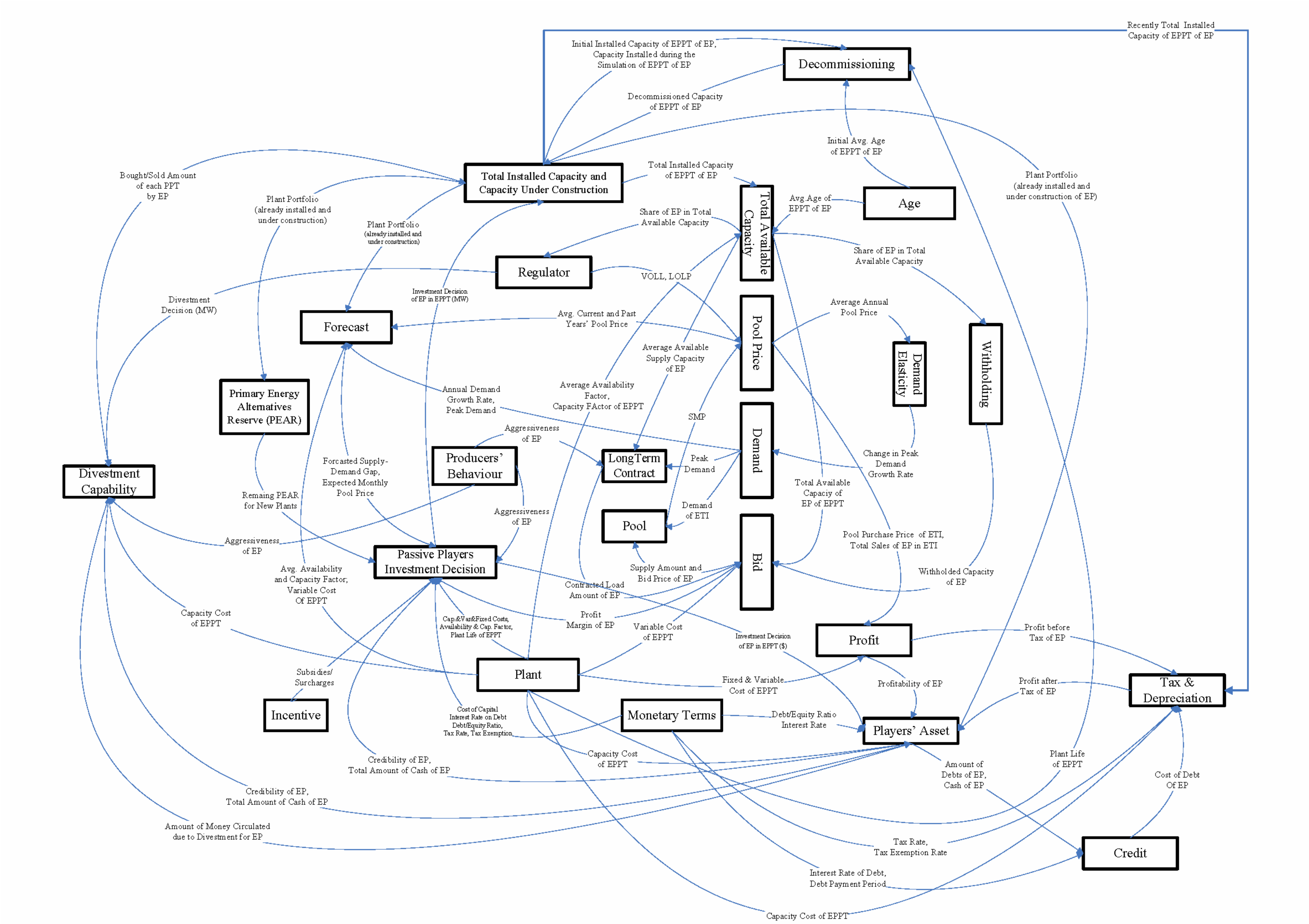


Figure 5.14. Major flows between sector groups of the model

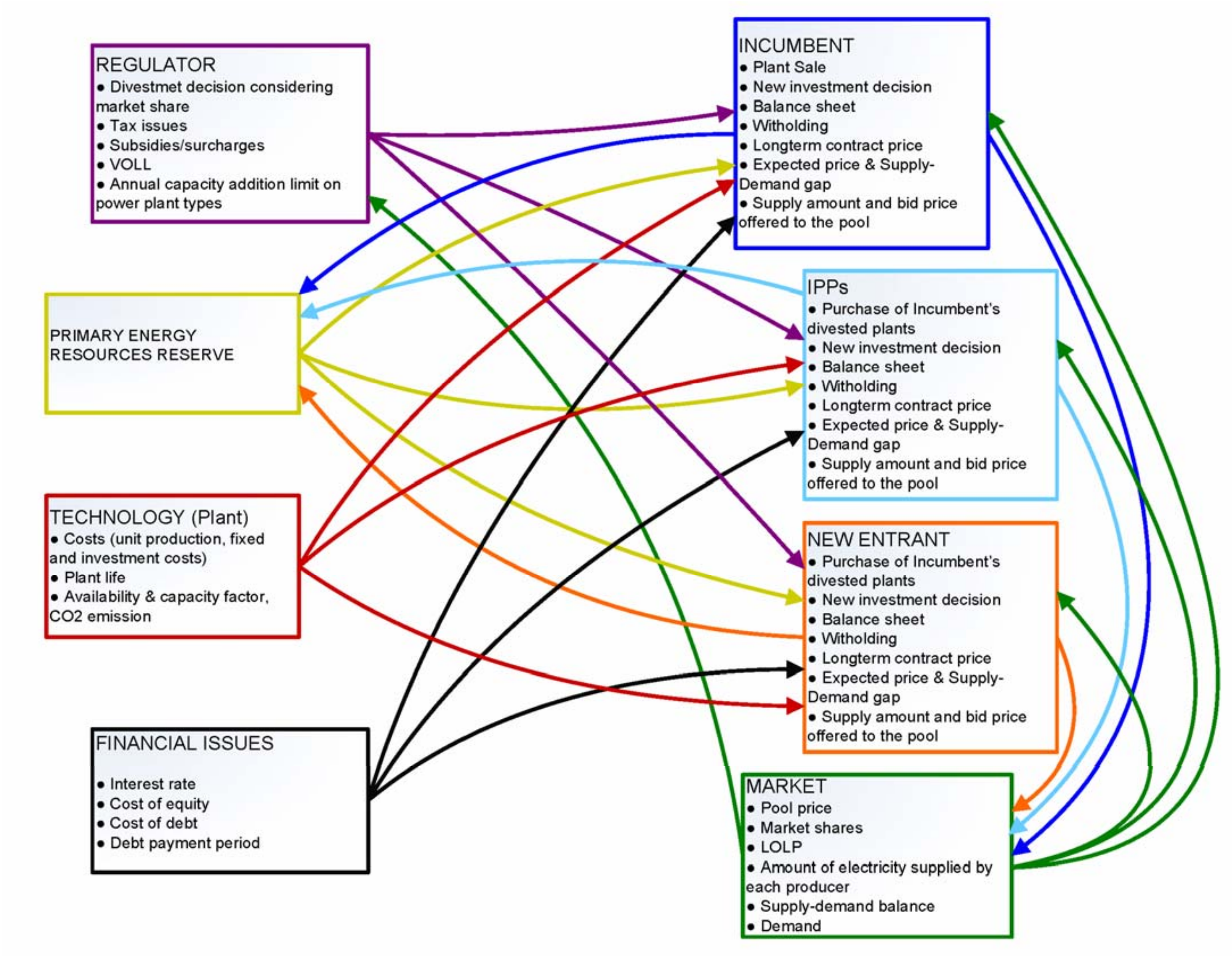


Figure 5.15. The subsystem diagram of LEMM

6. MODEL VALIDATION AND SENSITIVITY ANALYSIS

6.1. Introduction

This chapter focuses on the analysis of the model structure and behavior in order to check whether they produce valid behavior patterns for the model outputs, suitable regarding the real system they represent.

As system dynamics models are most generally developed to be used for policy design and analysis, the ultimate objective of the validation of these models is to establish the structural validity of the model. Structure validity is explained in (Barlas and Kanar, 1999) as follows; “Structure validation is establishing that the relationships used in a model are an adequate representation of the real relationships and it can be done in two ways: direct structure testing and indirect structure (or structure-oriented behavior) testing. Direct structure tests assess the validity of the model structure, by direct comparison with knowledge about real system structure. This involves evaluating each relationship in the model against available knowledge about real system. These tests are qualitative in nature; no simulation is involved.” Structure-oriented behavior tests on the other hand assess the validity of the structure indirectly, by applying extreme condition tests and behavioral sensitivity analysis.

i. Extreme Condition Tests: Models should be robust in extreme conditions. Robustness under extreme conditions means the model should behave in a realistic fashion no matter how extreme the inputs or policies imposed on it may be. Extreme condition test involves assigning extreme values to selected parameters and comparing the model-generated behavior to the “anticipated” (or observed) behavior of the real system under the same extreme condition. When an extreme condition simulation generates implausible behavior, the equations of the affected formulations should be examined to identify the precise source of the flaw. (Sterman, 2000).
ii. Behavioral Sensitivity Analysis: consists of determining the parameters to which the model is highly sensitive and asking if the real system is also sensitive to those set of parameters.

Any contradictions in the tests forwarded above point to possible structural flaws in the model.

6.2. Validation of the Developed Model

6.2.1. Sources of Information Used in the Model

To have a valid model, first of all, the data used to build the structure and relationships in the model should be reliable. In the developed model, three types of data (numerical, mental and textual) are used. The categorization of the data used in the model depends on the data classification stated in (Forrester, 1980).

A numerical database, which conveys less information than the other two groups, contains statistics and measurements, but does not provide any information about the relationships of the data points. In the developed model, assumptions related with the technological parameters of the power plant types (such as economic life, availability and capacity factors, costs etc.) and demand related parameters (initial peak demand, annual demand growth rate) are made through the numerical database.

The textual data contains long-term experience reflected to general theories published in journal papers and textbooks. The generality of the theories may not conform to the particular problem of interest, but are on the other hand more generally applicable. This source of data contains less information than a mental database, because theoretical descriptions are simplifications of reality in some manner. For example, a manager can't run his firm just by implementing what the theories and procedures states in textbooks. Such an endeavor would simply be impossible because such information cannot replace the embedded experience and routine of the operators of a system. Because of this reason, textual data conveys less information in the system dynamics model as compared to a mental database.

In this study, throughout the modeling process, relying on textual data (primarily based on (Stoft, 2002)) has been a great help in determining the relationships between different components and modules in the model and to determine the boundary of the system.

A mental database is by far the richest source of information. Mental data span all the information in people's mental models, including their impressions, their perception of the system and how decisions are actually made (sometimes, they oppose the written materials), how exceptions are handled, etc. Mental data cannot be accessed directly, but must be obtained through interviews and observations.

During the modeling process, various sub models have been developed and tested before they were integrated to form a complete system model. At each phase of the modeling, besides international literature, expert opinions have been considered in determining the model structure, relationship between entities, parameters and equations used in the model. (i.e. Direct structure tests are conducted throughout the modeling process)

6.2.2. Dimensional Consistency

Dimensional consistency is one of the most basic tests and should be among the very first that the model-developer should accomplish. For example, during the development of the LEMM, each equation is checked whether it is dimensional consistent or not.

In fact, Stella includes automated dimensional analysis so that the model-developer can test his model for dimensional errors with a single command, in case the model does not include any arrayed variables. However, since the LEMM included arrays, dimensional analysis feature of the Stella couldn't be utilized.

6.2.3. Structural Validation of the Developed Model

As it is explained in Section 6.2.1 direct structure test are conducted during the modeling process of the LEMM.

After conducting direct structure tests, indirect structure tests, consisting of extreme condition tests and behavior sensitivity analysis, are also conducted on the developed model.

The following assumptions, are made in the analysis throughout this chapter.

- The forecast period is 2 years.
- The VOLL is 2000 $/MWh.
- The tax rate is 20 per cent.
- The annual interest rate on debt is 7 per cent.
- Time value of money at hand is 7 per cent.
- The cost of equity is 11.5 per cent (when the debt-equity ratio is zero).
- Profit margins of the producers are;
  - 27 per cent for the Incumbent;
  - 40 per cent for the New Entrant;
  - 31 per cent for the IPP1;
  - 31 per cent for the IPP2;
  - 32 per cent for the IPP3.
- All investors are conservative and driven by computer (i.e. all the investors are passive players).
- The debt equity ratio is 3.
- The tax exemption rate is 40 per cent.
- No withholdings, no long-term contracts, no price elasticity of electricity demand, no CO_2 tax, no state support for renewable energy, and no annual capacity addition limits on power plant types exist in the market.
- The reserve of imported primary energy resources (natural gas, diesel oil, hard-coal) is four times the initial (i.e current) value of country's potential.
- The reserve of domestic primary energy resources is 1.5 times of the initial (i.e current) value of country's potential.
- Investors do not have any outstanding loans at the beginning of a simulation run.

- The overall initial installed capacity and capacity under construction is based on the current situation of the Turkish Electricity Market and the values presented in Table 6.3 and Table 6.4 are used.

The simulation output of the base scenario for major performance indicators is presented through Figure 6.1–Figure 6.14, in order to provide a comparison basis for the simulation outputs obtained through extreme condition tests and sensitivity analysis.

Figure 6.1 illustrates the dynamics of the total installed capacity throughout the planning horizon. Through Figure 6.1- 6.9, it is observed that there are two different behavior patterns; at the earlier stages of the planning horizon a linearly increasing pattern is observed, while a stepwise increasing pattern becomes dominant at the later stages. The main reason for these behavior patterns in the related figures is that different types of delays are deployed in the construction lead times. First order delay is assumed for the construction lead time of the initial power plants under construction, whereas pipeline delay is assumed for the plants started to be constructed during the planning horizon. (Detailed explanation of the plant construction delays are given in Section 5.2.5.) On the other hand, as Figure 6.2, Figure 6.4 and Figure 6.8 illustrate, a portion of diesel oil, imported hard coal and wind plants, are decommissioned in the last quarter of the planning horizon.

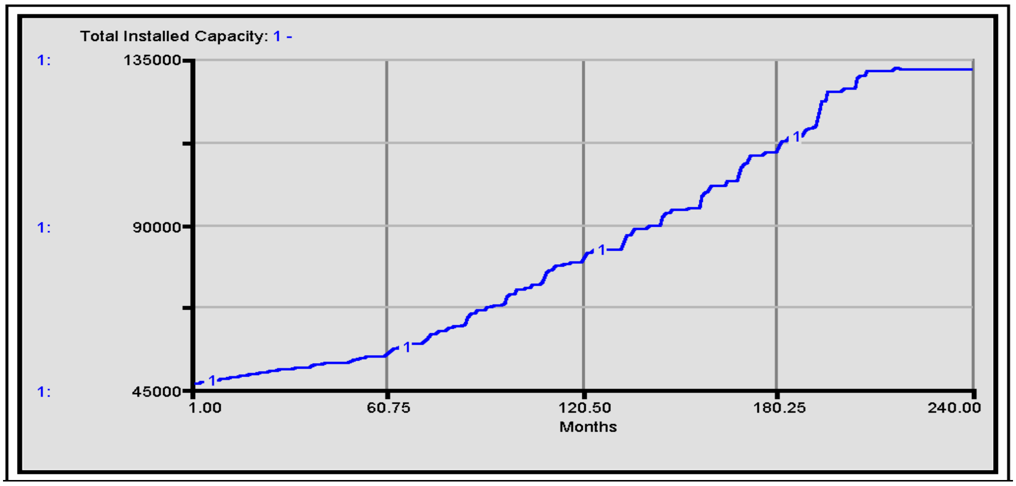


Figure 6.1. Total installed capacity (MW) in the base scenario

Through Figure 6.2-6.9, it is observed that investors mainly invest on small-hydro and natural gas power plants, thanks to their low investment costs, until all of the natural gas and small-hydro potential is utilized. Although there exists unutilized reserve amounts of the related primary energy resources in the market, investors do not invest on lignite, diesel-oil, wind and imported-hard coal power plants due to their high investment and variable costs.

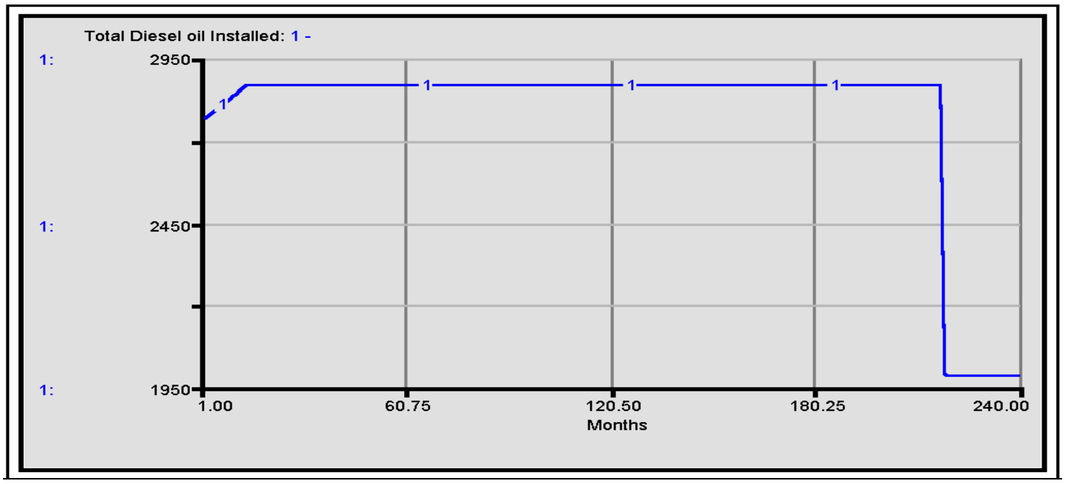


Figure 6.2. Total installed diesel-oil power plant capacity (MW) in the base scenario

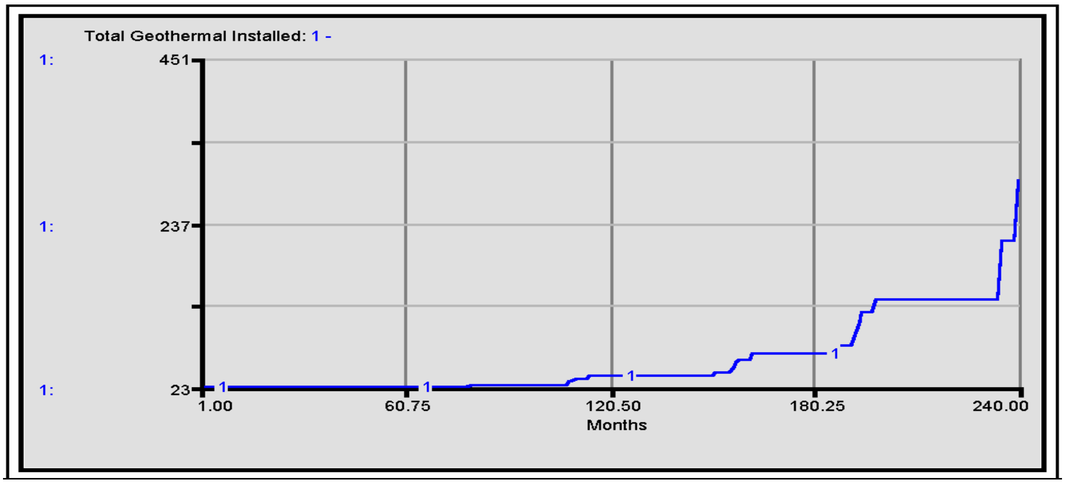


Figure 6.3. Total installed geothermal power plant capacity (MW) in the base scenario

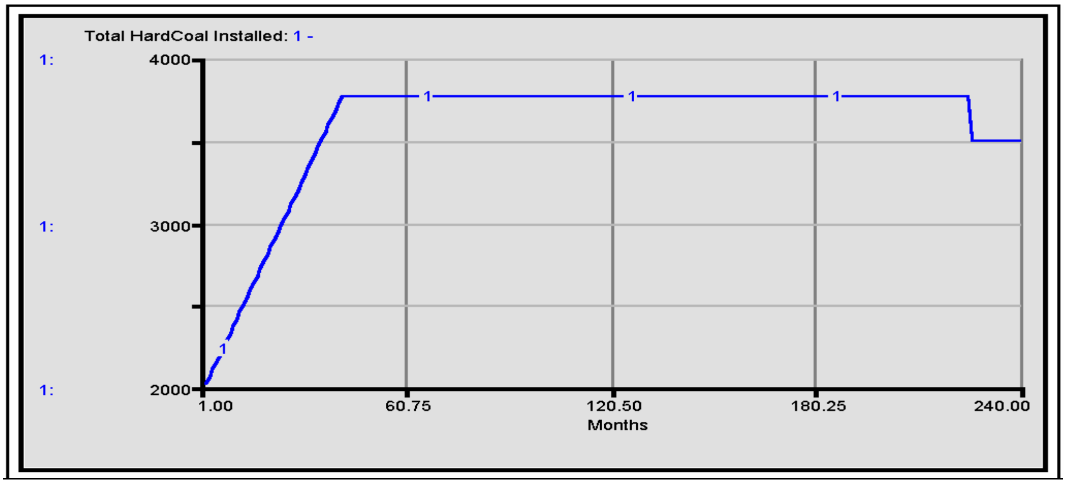


Figure 6.4. Total installed imported-hard coal plant capacity (MW) in the base scenario

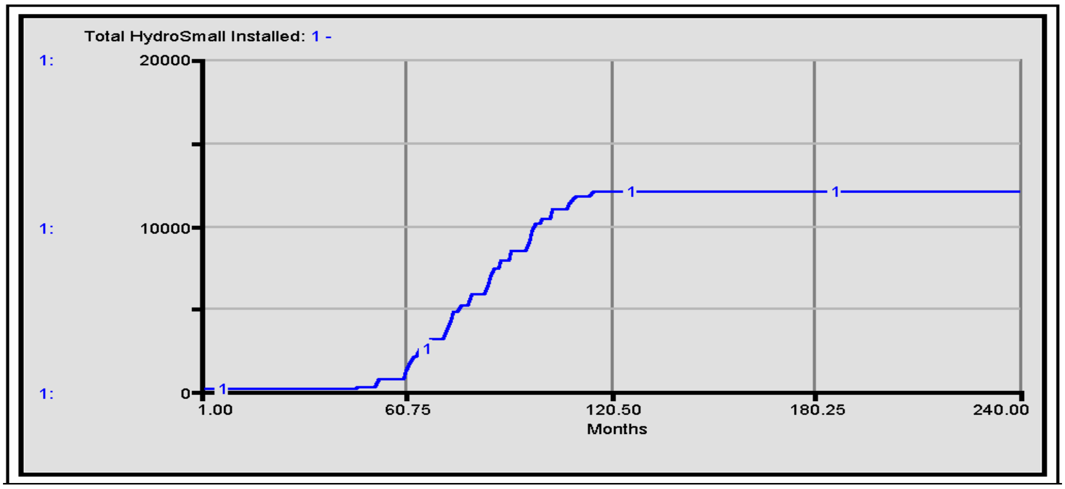


Figure 6.5. Total installed small-hydro power plant capacity (MW) in the base scenario

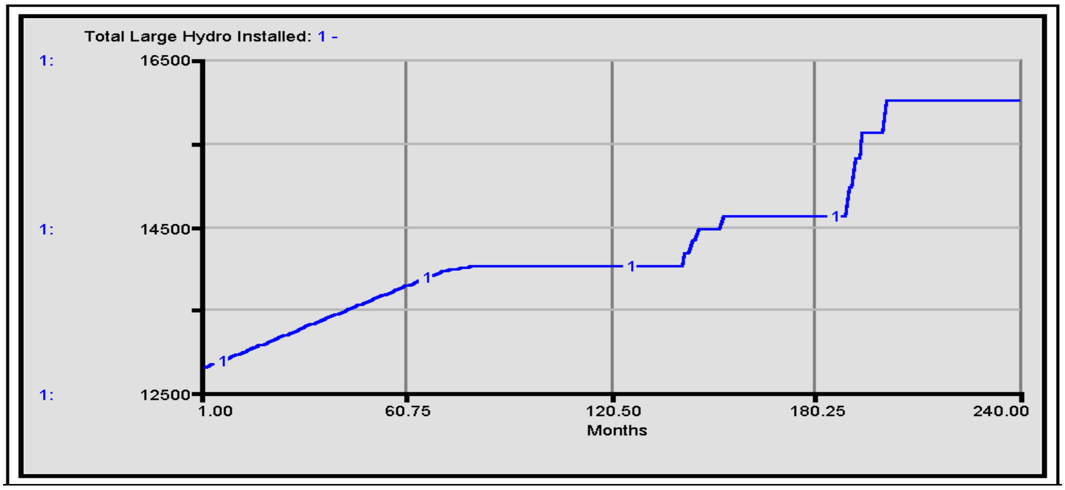


Figure 6.6. Total installed large-hydro power plant capacity (MW) in the base scenario

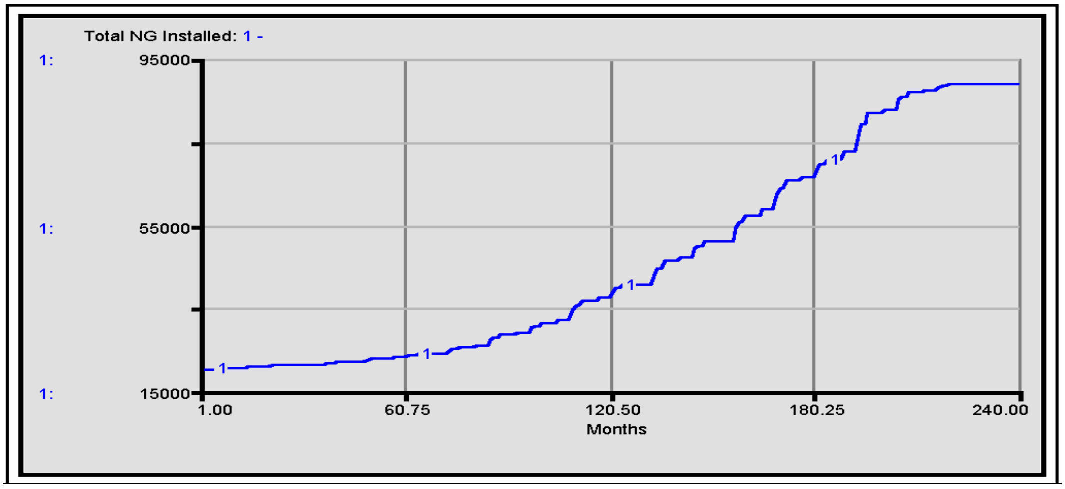


Figure 6.7. Total installed natural gas power plant capacity (MW) in the base scenario

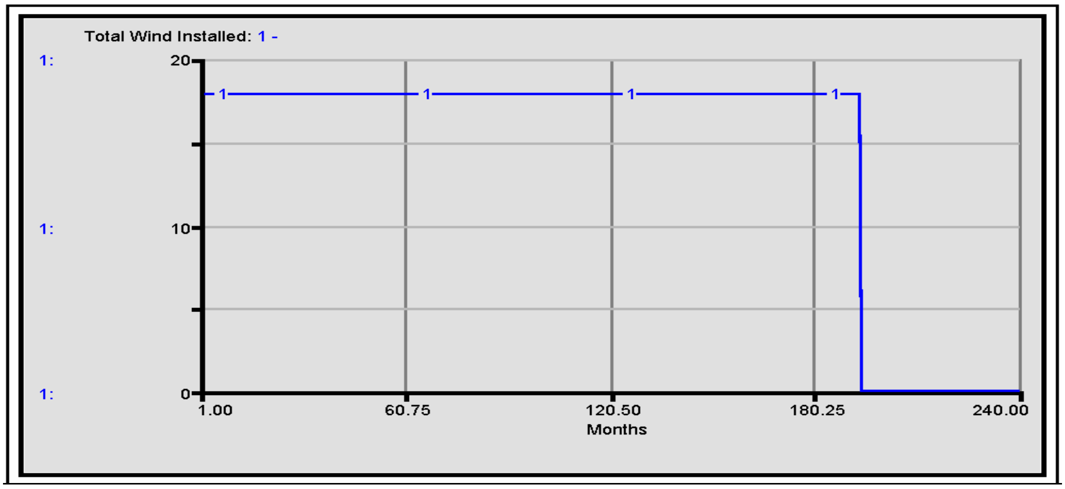


Figure 6.8. Total installed wind power plant capacity (MW) in the base scenario

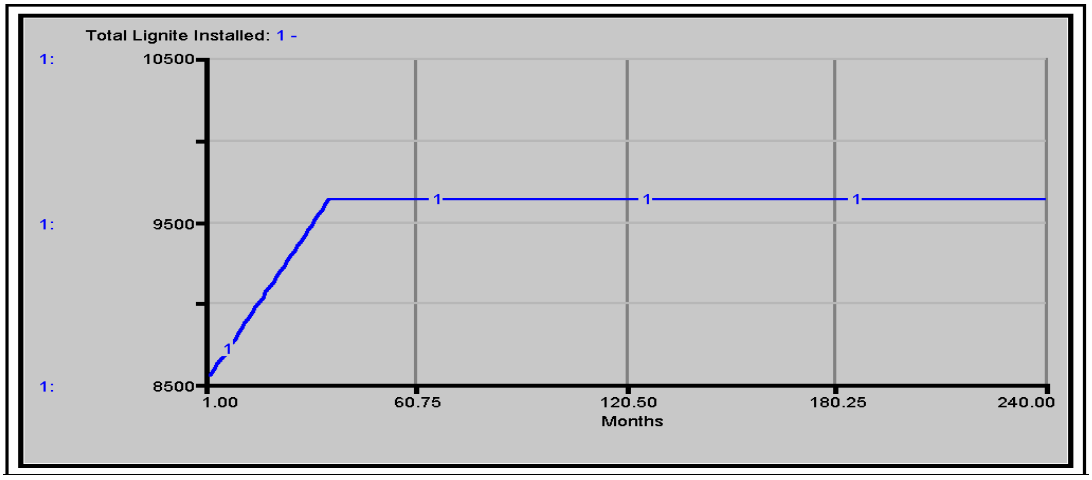


Figure 6.9. Total installed lignite power plant capacity (MW) in the base scenario

Additionally, total installed capacity of the thermal and renewable power plants at the end of the planning horizon is 104.614 MW and 28.302 M, respectively.

Figure 6.10 displays average monthly pool prices, (i.e. the weighted average of the pool prices observed during the nine different time intervals in a day)

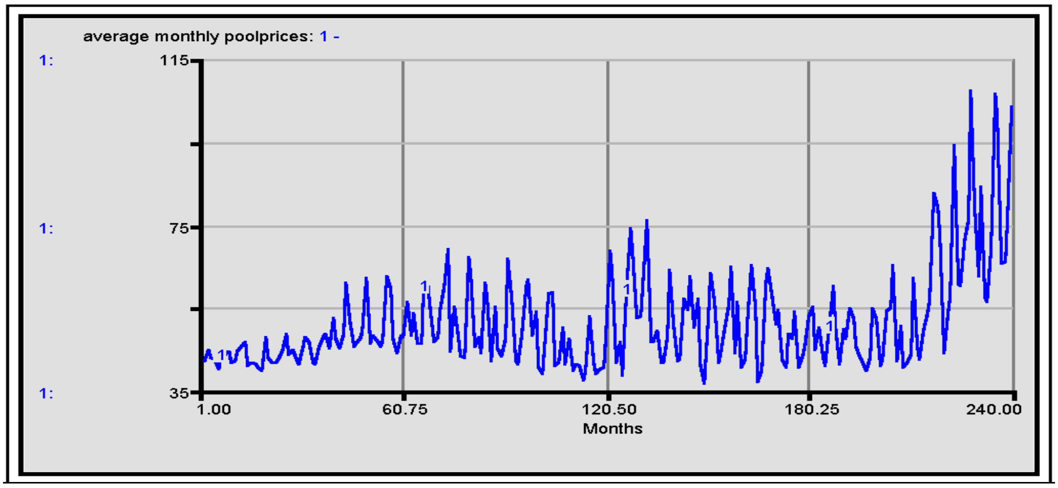


Figure 6.10. The average monthly pool price ($/MWh)

Figure 6.11 displays the monthly electricity reserve margin observed during the planning horizon. Since, the current total installed capacity and capacity under construction in the Electricity Market is not enough to meet prospective demand, there is a decline in the electricity reserve margin until the 60th month, while an increase is observed later on, since by then the new plants under construction start getting in line. Tooth-saw pattern observed in the reserve margin results from the seasonal and monthly variations in the electricity demand and the fluctuating capacity factors of the wind and hydro power plants. The sharp decrease in the reserve margin dampens the overall tooth-saw pattern during the fist quarter and last 30 months of the planning horizon.

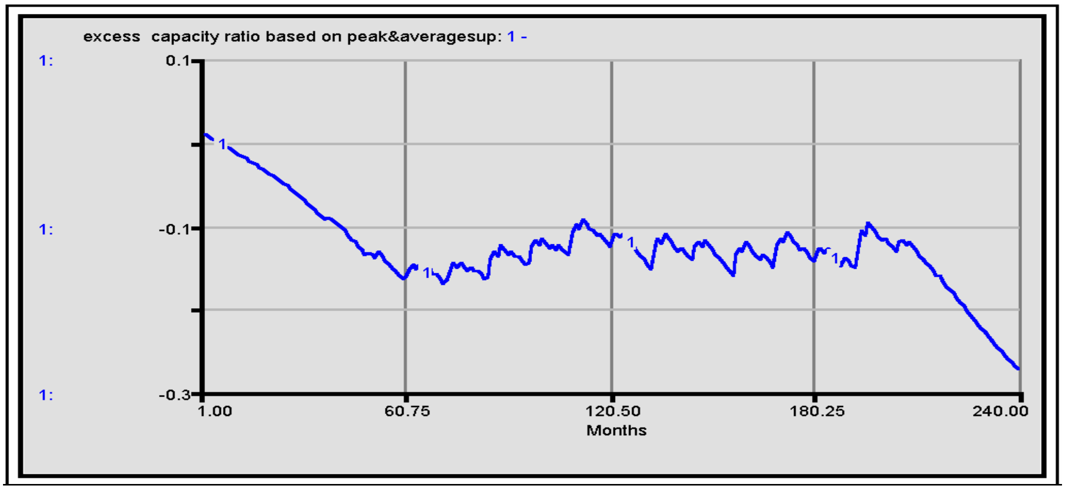


Figure 6.11. The electricity reserve margin (per cent)

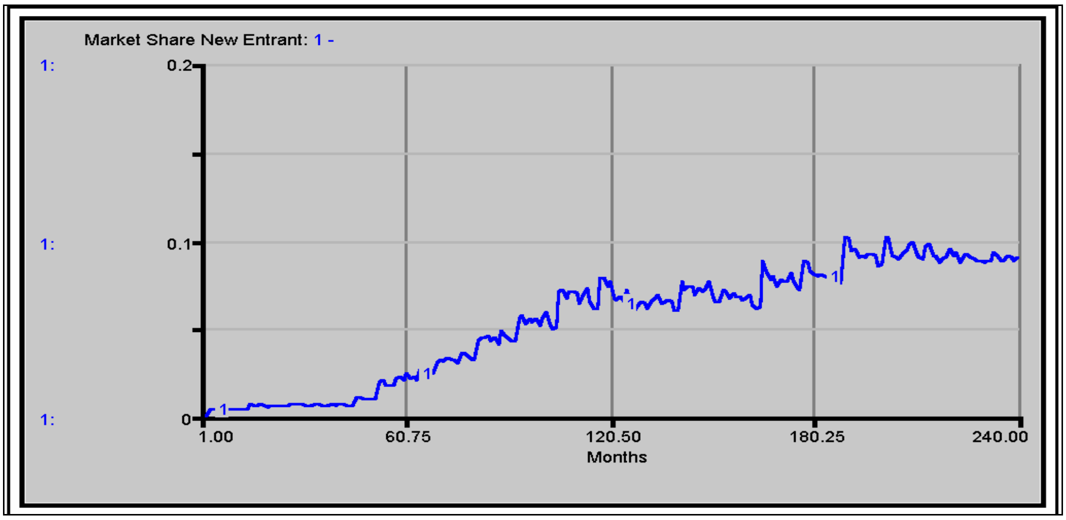


Figure 6.12. Market share of the New Entrant

Figure 6.12 displays the market share of the NE. The NE enters the market either by purchasing the divested power plants of the Incumbent or by constructing new power plants. As can be observed in the Figure 6.12, the NE buys a small portion of the Incumbent's installed capacity at the beginning of the planning horizon. Towards the 60th month, the new plants, that the NE has constructed, are introduced to the market; in the long-run, the NE's market share is around 10 per cent.

<u>6.2.3.1. The Extreme Condition Tests</u>. The following cases are considered in the extreme condition analysis:

i. The peak demand is set to a minimal value of 1 MW. (Actually, it is desirable to test the zero demand case but setting the peak demand to zero could lead to some unwanted minor difficulties, such as division by zero's.). Then peak demand is set to an extremely hig value, 200,600 MW.
ii. Tax rate is set to 100 per cent.
iii. The remaining economic lives of existing plants at the beginning of the planning horizon are set to minimal times.
iv. The country's resource potential for natural gas, imported-hard coal and diesel oil plants are assumed to remain unchanged (at their current levels). As such, no additional new supply contracts and no new domestic resource discovery is considered to be an extreme case.
v. Interest rate of loans is analyzed at two extreme values; 1 per cent and 100 per cent.

6.2.3.1.1. The Peak Demand. As an extreme condition analysis peak demand is set to 1 MW and 200,600 MW. The expected and observed behavior patterns under this extreme case are explained below.

Since there is no prospective supply gap during the planning horizon, in the 1 MW initial peak demand value;

i. No new investment decision is expected during the planning horizon. In other words, total installed capacity is expected to increase only because of the power plants under construction at start and then stay constant until some plants are decommissioned. Behavioral pattern of total installed capacity is given in Figure 6.13 and behavioral pattern of total installed diesel-oil plant is illustrated in Figure 6.14, as a representative of the behavioral pattern of the other power plant types as well. These patterns are in line with our expectations.
ii. As explained previously, no new investment is made on power plants so, no new entry is expected in the market. In other words, total installed capacity of the NE is expected to be zero, in line with the simulation output displayed in Figure 6.15.

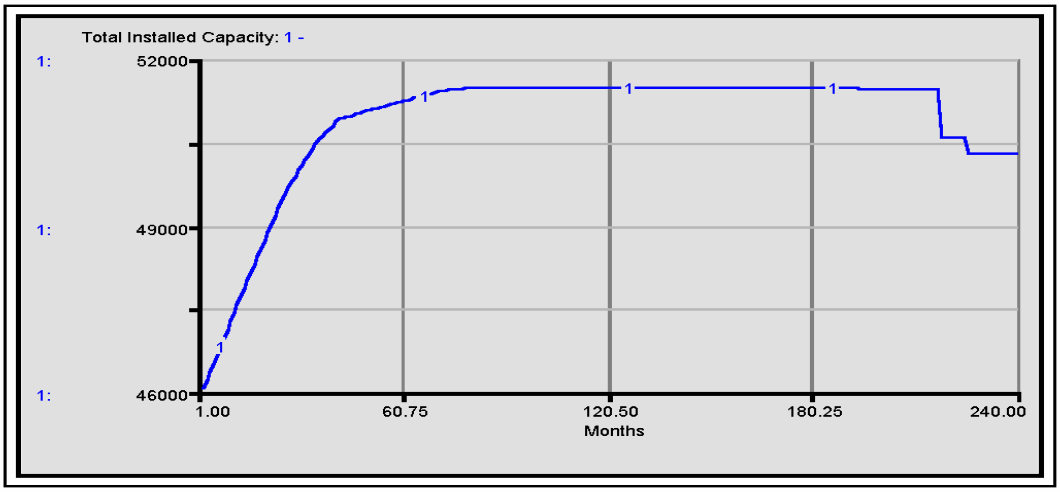


Figure 6.13. Total installed capacity (MW) in the case of 1 MW initial peak demand

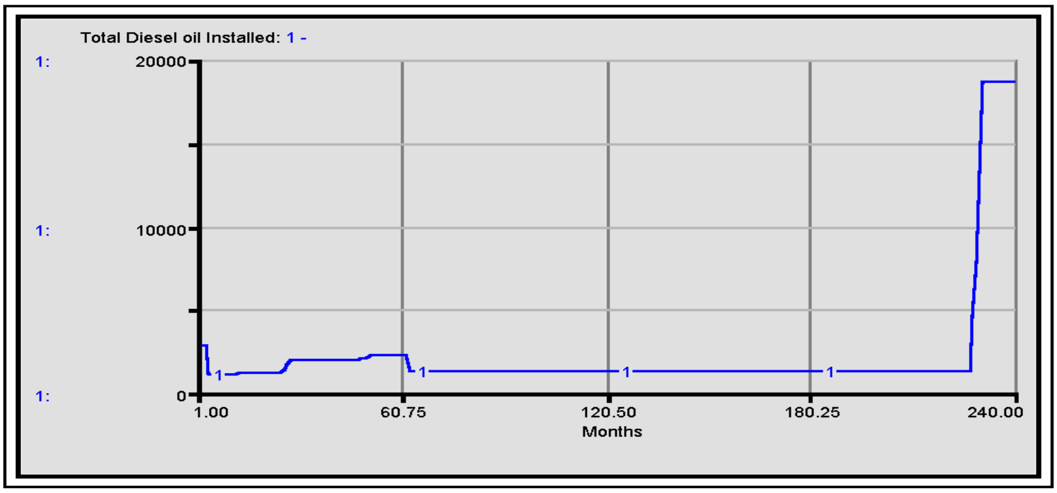


Figure 6.14. Total installed diesel-oil plant capacity in the case of 1 MW initial peak demand

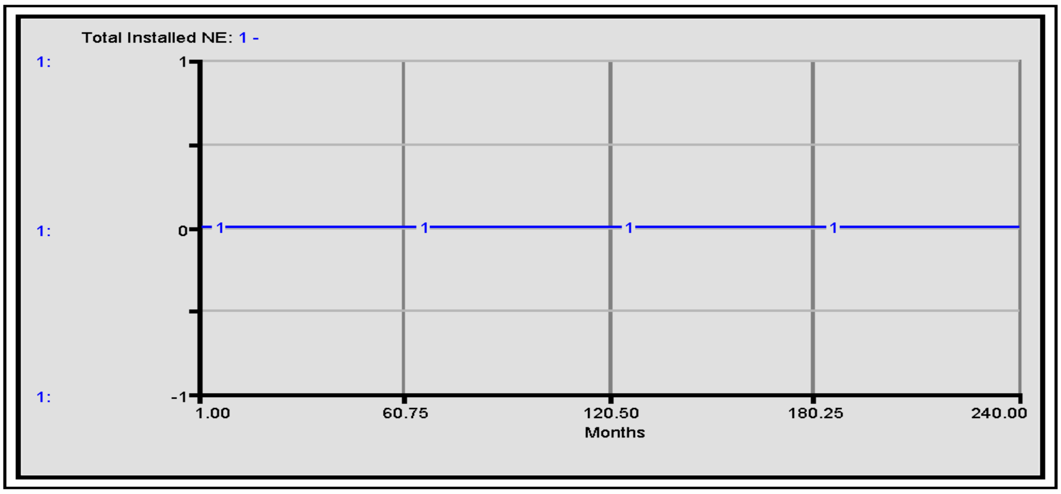


Figure 6.15. Total installed capacity of the NE in the case of 1 MW initial peak demand

iii. As there is an extremely high reserve margin, (displayed in Figure 6.17) in the market, the investors have great difficulty in selling electricity to the pool system. Since the lowest bid price is offered by the Incumbent and his total installed capacity, displayed in Figure 6.18.,is enough to meet the demand, only the Incumbent can sell electricity in the market. (Accordingly, throughout the planning horizon, the market share of the Incumbent is 100 per cent, whereas the other investors' market share is zero) This market share behavior pattern of the Incumbent is displayed in the Figure 6.16 and it confirms with our expectations.

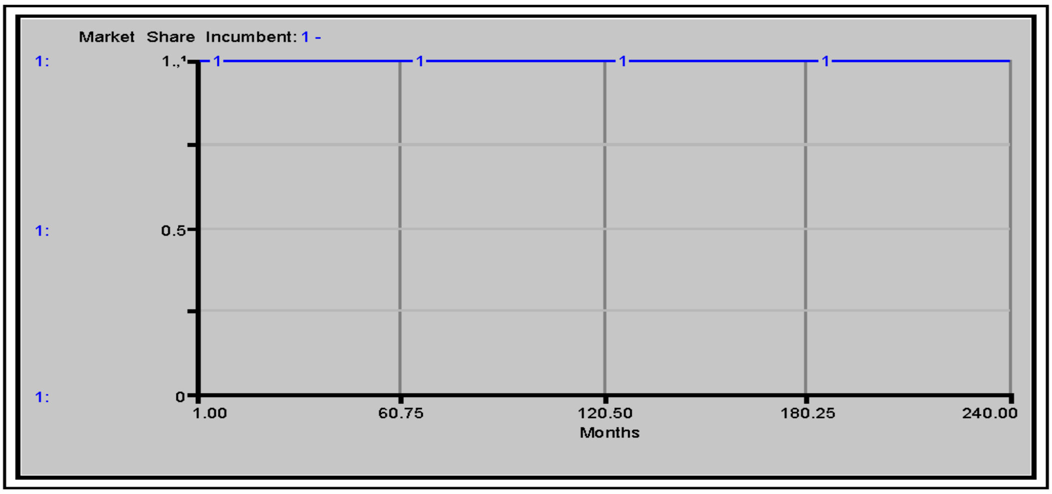


Figure 6.16. The market share of the Incumbent in the case of 1 MW initial peak demand

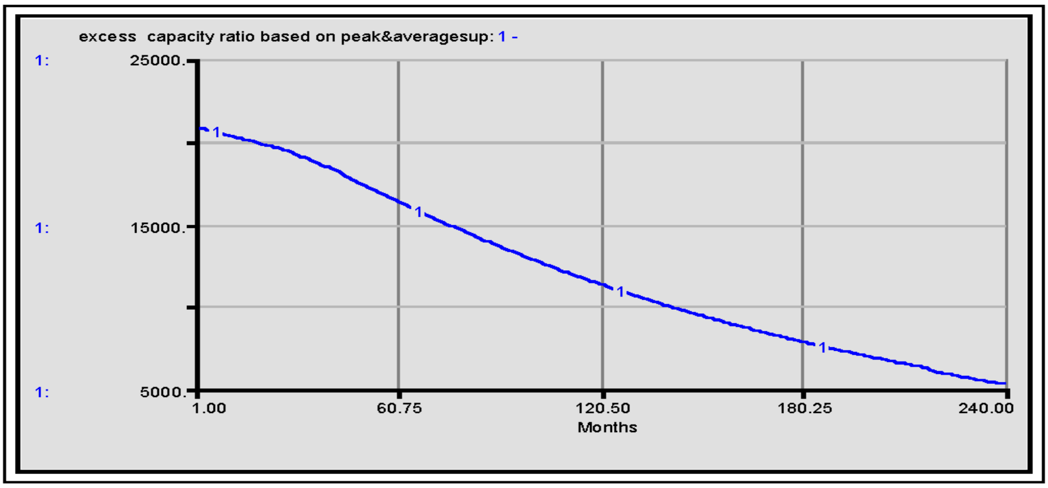


Figure 6.17. The reserve margin (per cent) in the case of 1 MW initial peak demand

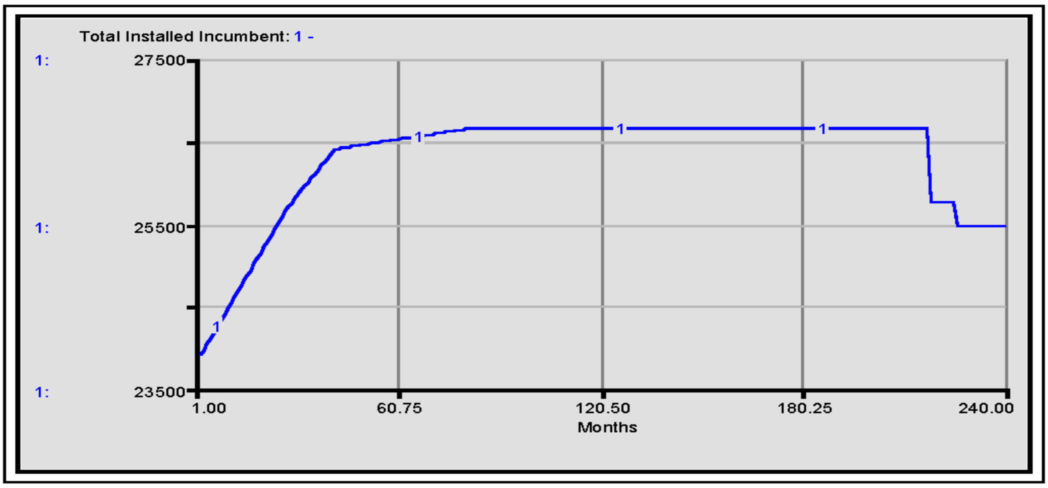


Figure 6.18. Total installed capacity of the Incumbent in the case of 1 MW initial peak demand

Since there is extremely high supply gap during the planning horizon, in the case of 200,600 MW initial peak demand;

i. Pool prices are expected to be extremely high due to low electricity reserve margin. This expectation is in line with the simulation output displayed in Figure 6.22.

ii. Since pool prices and prospective supply gap are extremely high, the investors are expected to invest on power plants as much as the primary energy resources' reserves allow them. Throughout Figures 6.19-6.21, it is observed that there exist steep increases in the total installed capacity of each power plant type throughout the first half of the planning horizon, but then no increase in the total installed capacity is observed within the second half of the planning horizon, since the primary energy resources' reserves are fully exploited. On the other hand, since no additional power plant is introduced to the electricity market (due to totally utilized primary energy resources' reserves), and continuous increase in the demand, (due to price inelastic demand assumption), pool price keeps increasing during the last three quarters of the planning horizon as illustrated in Figure 6.22. These patterns are in line with expectations.

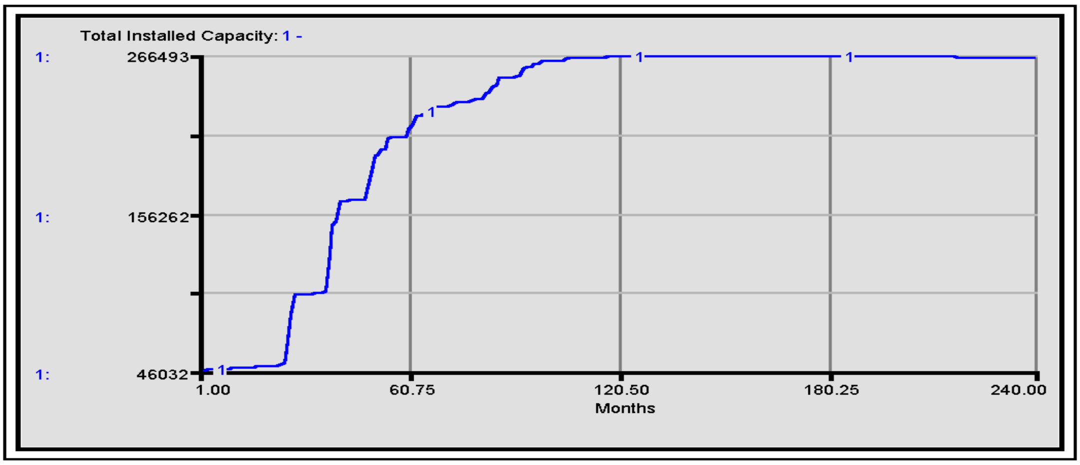


Figure 6.19. Total installed capacity (MW) in the case of 200,600 MW initial peak demand

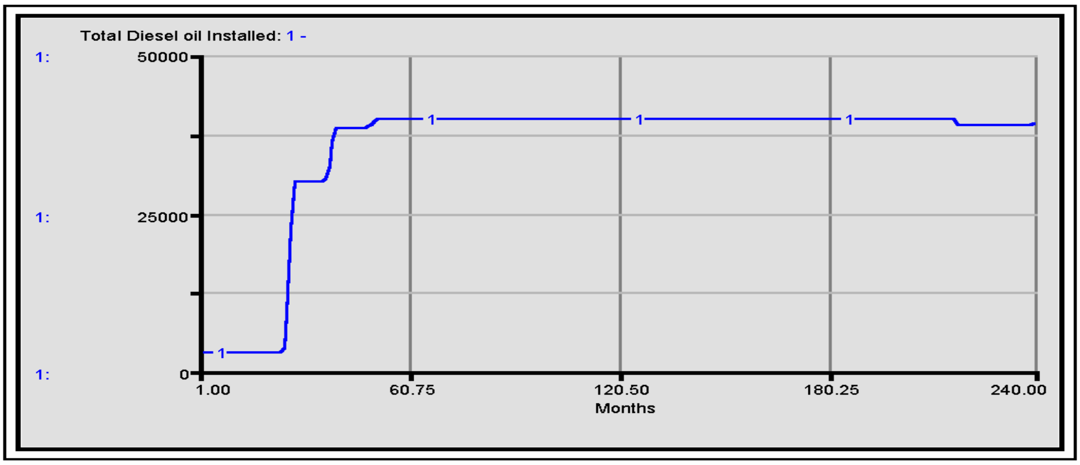


Figure 6.20. Total installed diesel-oil plant capacity (MW) in the case of 200,600 MW initial peak demand

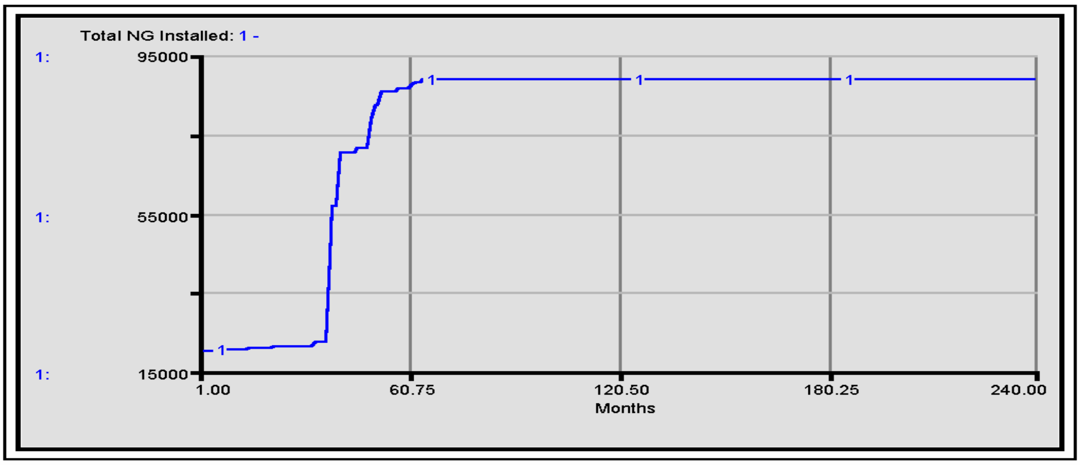


Figure 6.21. Total installed natural gas plant capacity (MW) in the case of 200,600 MW initial peak demand

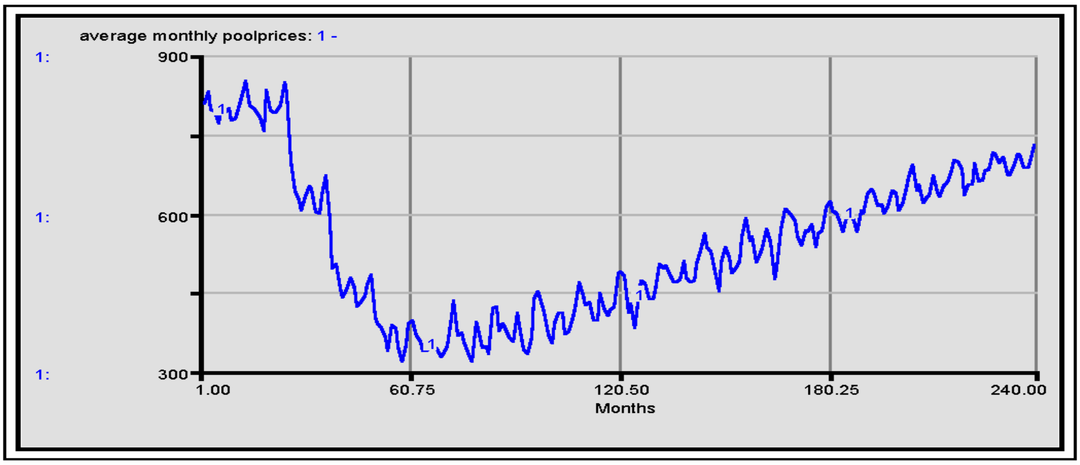


Figure 6.22. Average monthly pool prices ($/MWh) in the case of 200,600 MW initial peak demand

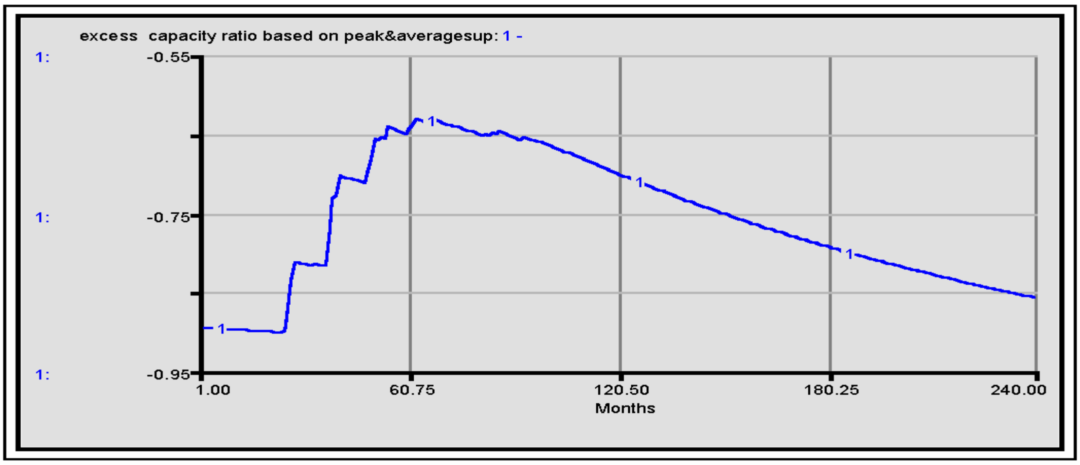


Figure 6.23. Electricity reserve margin (per cent) in the case of 200,600 MW initial peak demand

6.2.3.1.2. The Tax Rate. The tax rate is set to 100 per cent as an extreme condition. Actually, the 100 per cent tax rate is an irrational condition, wherein no investor should invest on new power plants, since all potential earnings will have to be paid as tax.

The expected and observed behavior patterns in case of the 100 per cent tax rate are explained below;

i. Total installed capacity is expected to increase linearly at the earlier stages of the planning horizon, as the initial plants under construction are introduced to the market. Excluding these, no increase in the total installed capacity is expected to be observed throughout the planning horizon, since power plant investments are not economically attractive owing to the 100 per cent tax rate. Total installed capacity is expected to decrease at the later stages of the planning horizon, as power plants start to get decommissioned. These expectations are parallel to the simulation output displayed in Figure 6.24.

ii. Since no new plant investment are made, and demand continuously increases (as it is assumed to be price inelastic), electricity reserve margin is expected to decrease gradually, in line with the simulation output, as depicted in Figure 6.25.

iii. Decreasing electricity reserve margin is expected to lead to increasing pool price and this expectation is not conflicting with the simulation output displayed in Figure 6.26.

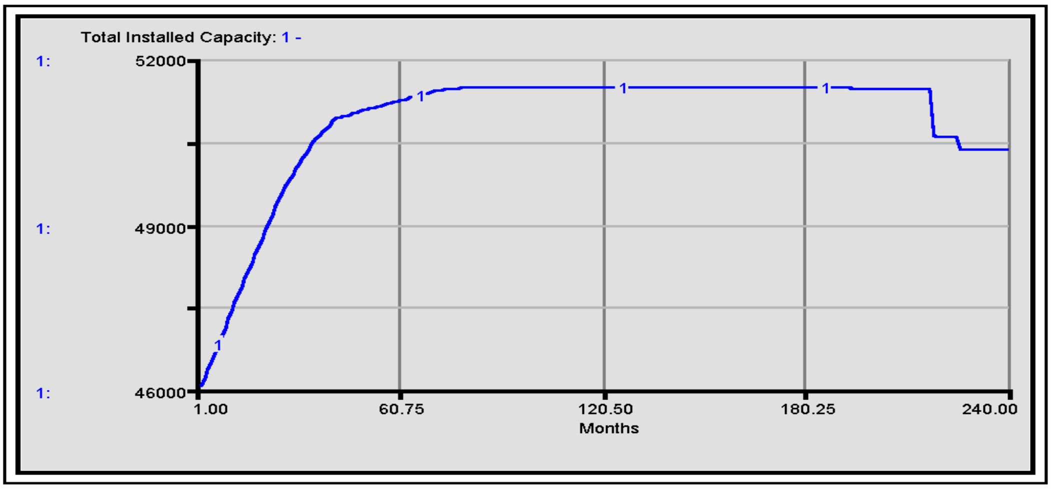


Figure 6.24. The total installed capacity (MW) in the 100 per cent tax rate case

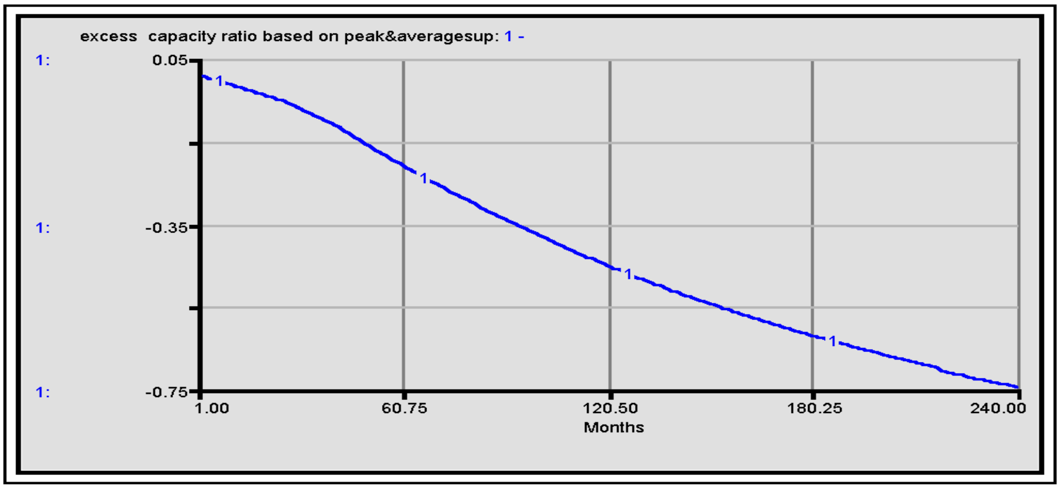


Figure 6.25. The electricity reserve margin (per cent) in the 100 per cent tax rate case

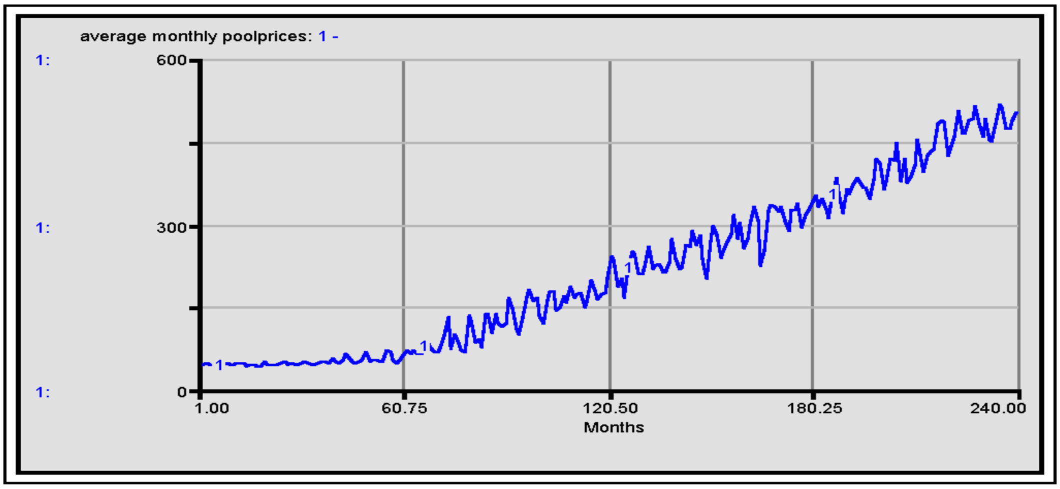


Figure 6.26. The average monthly pool price ($/MWh) in the 100 per cent tax rate case

6.2.3.1.3. The Average Age of the Initial Power Plant Portfolio. As another extreme condition analysis, an average current age of 20 years for wind plants and 30 years for other plant types are assumed for all plants in the initial portfolio (so, economic lives of all initial power plants, excluding hydro plants, are about to cease soon.) The expected and observed behavior patterns are cited below;

i. Power plants are to be decommissioned at very early stages of planning horizon; this expectation is confirmed with the simulation outputs displayed through Figures 6.28-Figure 6.30.

ii. Power plants replacing the decommissioned ones are to be introduced to the market after a long lead time (due to long construction times), as observed in the simulation outputs presented through Figures 6.27- 6.30.

iii. The market should suffer from a deep supply shortage. (i.e. reserve margin is to be extremely low), this expectation is not conflicting with the behavior displayed in Figure 6.32.

iv. Due to the supply shortage in the market, extremely high pool prices should prevail in the market, as observed in the simulation output depicted in Figure 6.32.

v. Owing to high pool prices, investors should perceive all types of power plants as attractive, and they should make new investments on all plant types. This expectation is inline with the simulation outputs, as displayed in Figures 6.27-6.32.

vi. Pool prices should gradually drop, as new power plants are introduced to the market and the supply shortage lessens throughout the planning horizon. This expectation is also in line with the simulation output, as displayed in Figure 6.32.

vii. The NE's market share should reach higher values (as compared to the base scenario), since high pool prices motivates the NE to invest more as compared to the base scenario, and the supply shortage allows all investors to sell as much as they offer to the pool. This expectation is parallel to the simulation output, as displayed in Figure 6.33.

As explained above, the expected behavior patterns are in line with the simulation outputs, as presented through Figures 6.27-6.33.

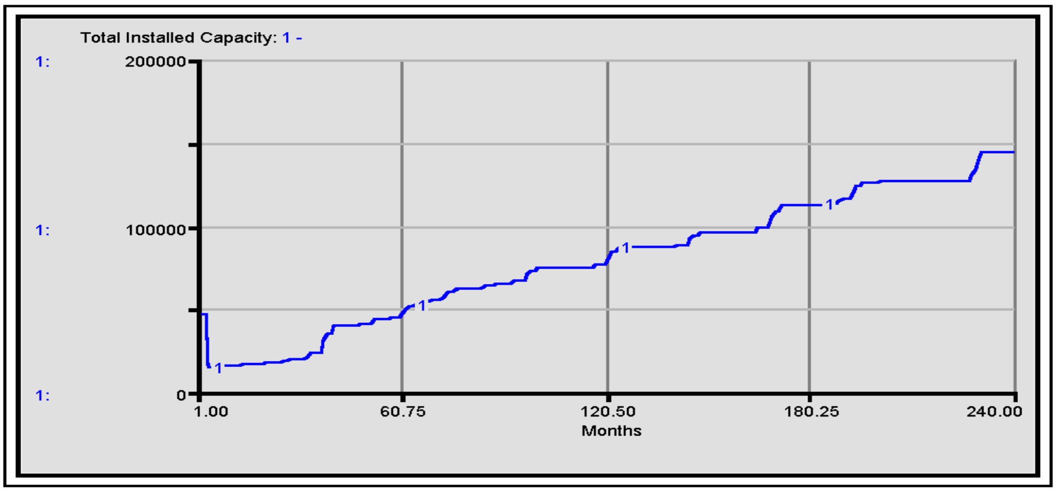


Figure 6.27. The total installed capacity (MW) in the case of initial power plants being at the end of their economic lives

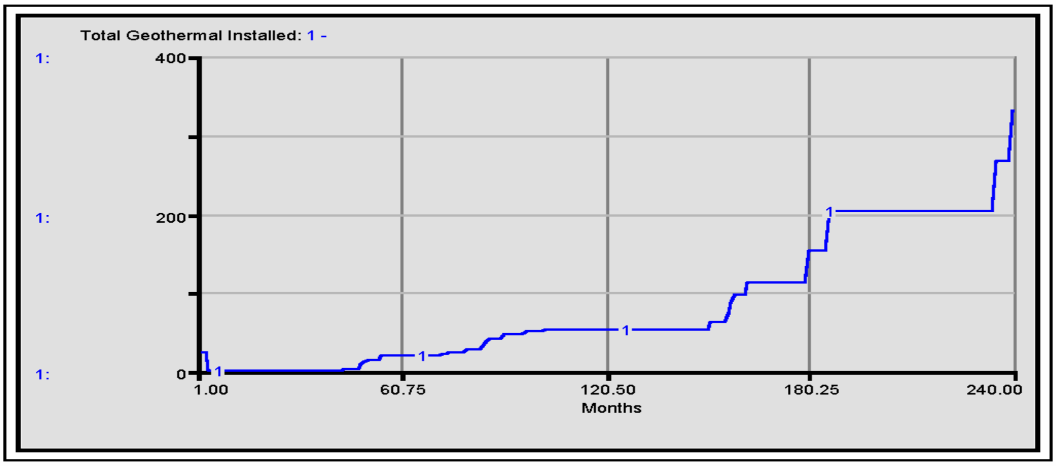


Figure 6.28. The total installed geothermal power plant capacity (MW) in the case of initial power plants being at the end of their economic lives

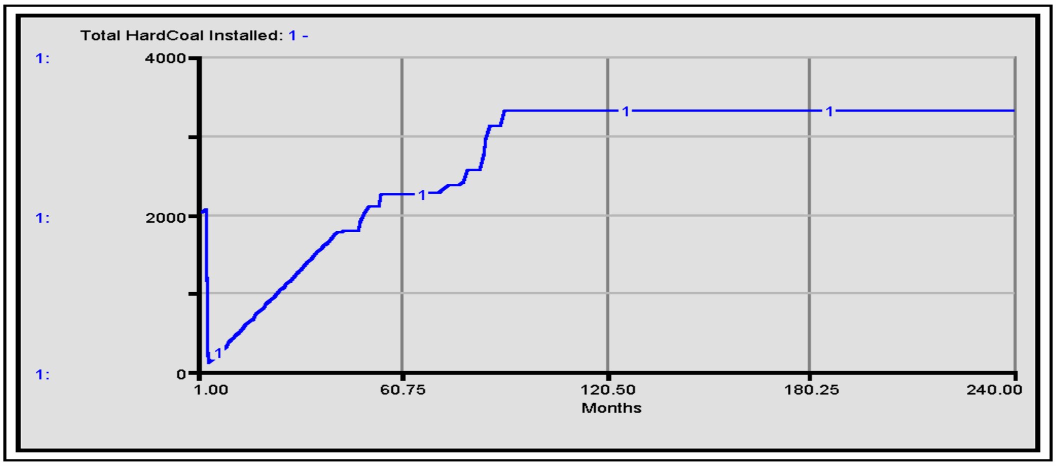


Figure 6.29. The total installed imported-hard coal power plant capacity (MW) in the case of initial power plants being at the end of their economic lives

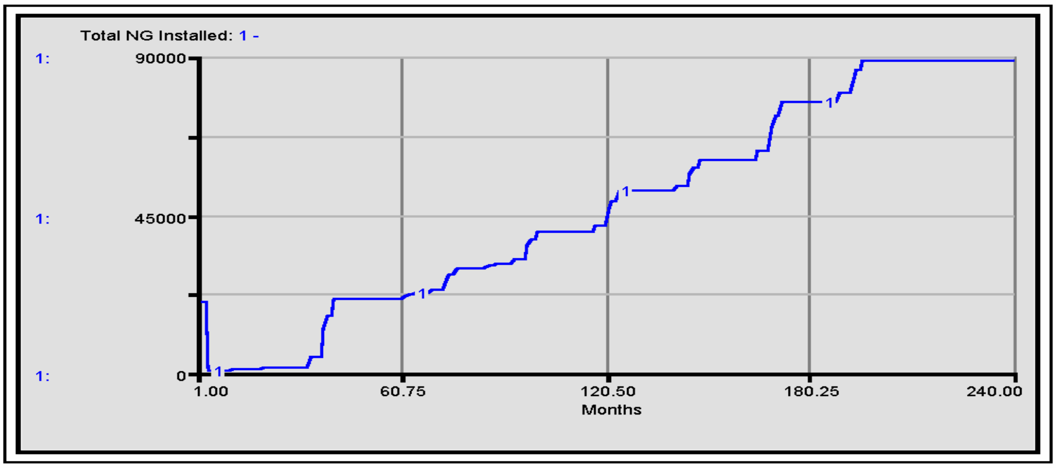


Figure 6.30. Total installed natural gas power plant capacity (MW) in the case of initial power plants being at the end of their economic lives

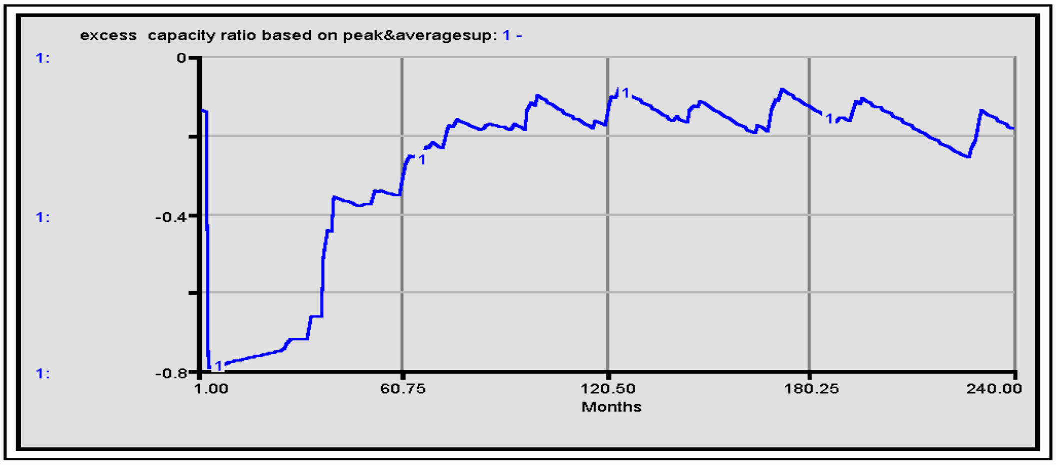


Figure 6.31. The electricity reserve margin (per cent) in the case of power plants being at the end of their economic lives

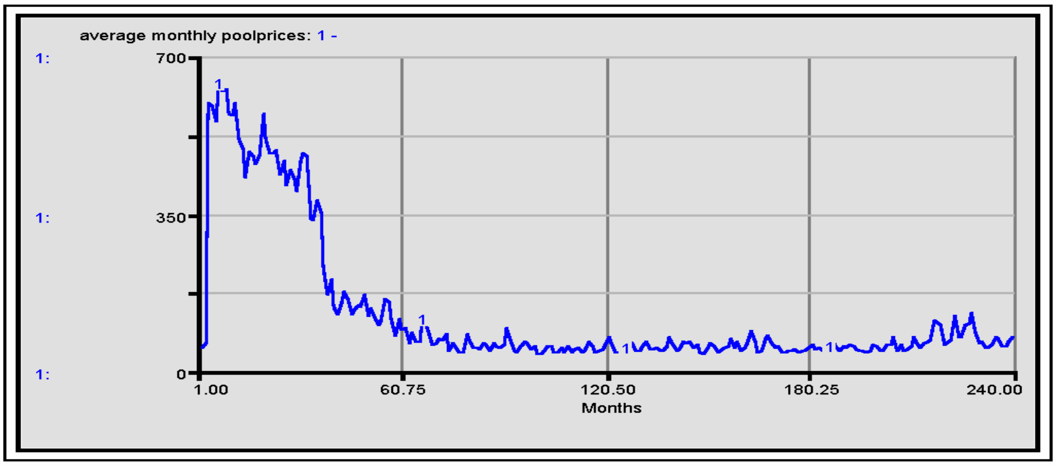


Figure 6.32. Average monthly pool prices ($/MWh) in the case of initial power plants being at the end of their economic lives

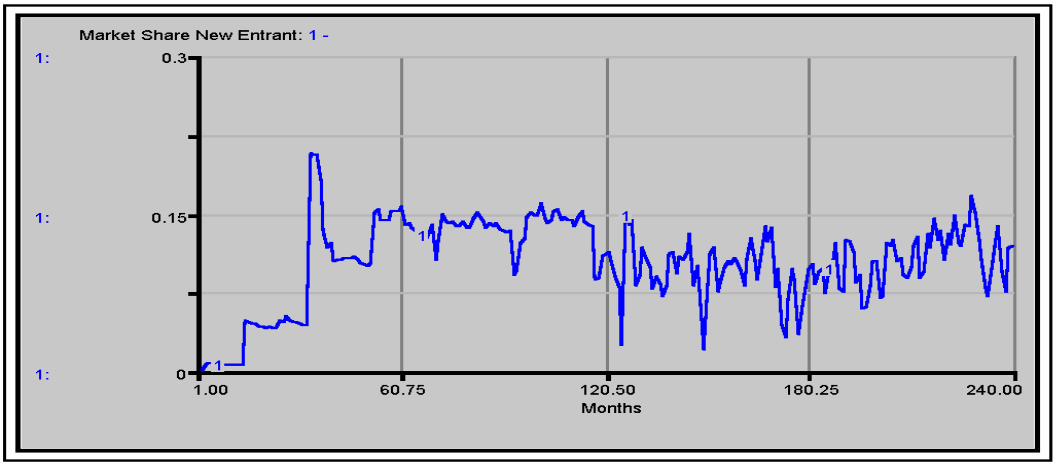


Figure 6.33. The market share of the NE in the case of initial power plants being at the end of their economic lives

<u>6.2.3.1.4. The Primary Energy Resources' Reserve.</u> As another extreme case, the reserve of imported primary energy resources (natural gas, diesel oil, hard-coal) is kept fixed at the initial (i.e current) value of country's potential throughout the planning horizon. (In other words, it is assumed that no new supply contracts could be made for 20 years, which is an extremely pessimistic outlook.)

As can be seen in Section 6.2.3., in case there are sufficient primary energy resources;

i. Investors prefer to build natural gas and small hydro-power plants, due to their comparatively low investment costs, over other power plant types.
ii. Investors build other plant types only if the pool price in the market is high enough.
iii. Wind and diesel-oil plants are rarely preferred, due to their high investment and variable costs.

Under the assumed extreme condition the following behaviors are expected and observed;

i. Natural gas reserve should diminish at earlier stages of the planning horizon, thus hindering the comissioning of new natural gas plants. As observed from Figure 6.39, after the 60th month, no natural gas power plant can be introduced to the market.
ii. Since investors can not invest on natural gas power plants, and initially pool prices are not high enough to invest on power plant types having high investment costs, electricity reserve should decrease. This expectation is in line with the simulation result, depicted in Figure 6.41.
iii. Thanks to the low electricity reserve, pool prices should increase at later stages of the planning horizon. This expectation is confirmed with the simulation output presented in Figure 6.40.
iv. As a consequence of high pool prices, investors will perceive all types of power plants as attractive, and they will invest on all types of power plants. This expectation is not conflicting with the simulation outputs, presented through Figures 6.35-6.39
v. Since imported primary energy resources are so limited in the market, it is expected that total installed renewable power plant capacity will be higher than that of the case in the base scenario, whereas total thermal power plant capacity is lower than

that of the case in the base scenario. This expectation is in line with the simulation outputs, which illustrated that total installed thermal plant capacity is 65.226 MW, whereas total installed renewable plant capacity is 48.632 MW, at the end of the planning horizon.

As explained above, the behavioral patterns observed through the simulation outputs are in line with the expectations.

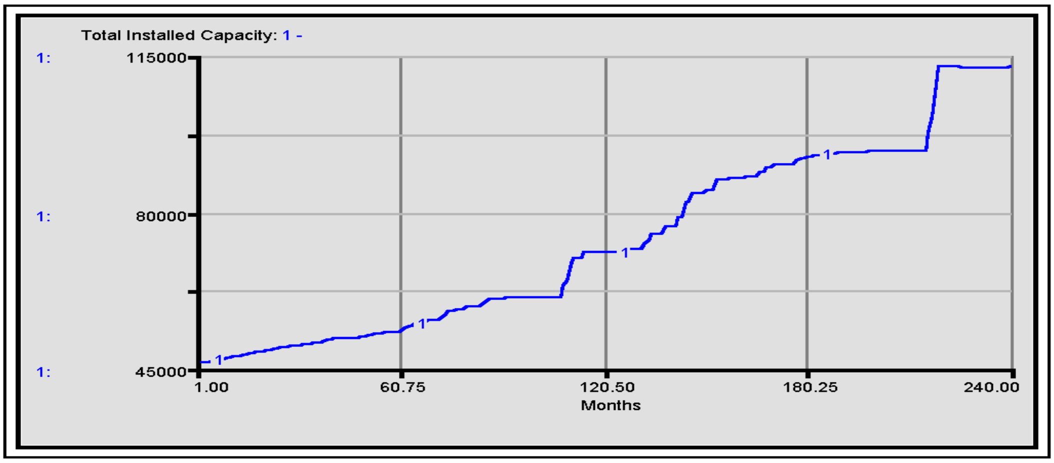


Figure 6.34. The total installed capacity (MW) in the case of very limited imported primary energy resources' reserve

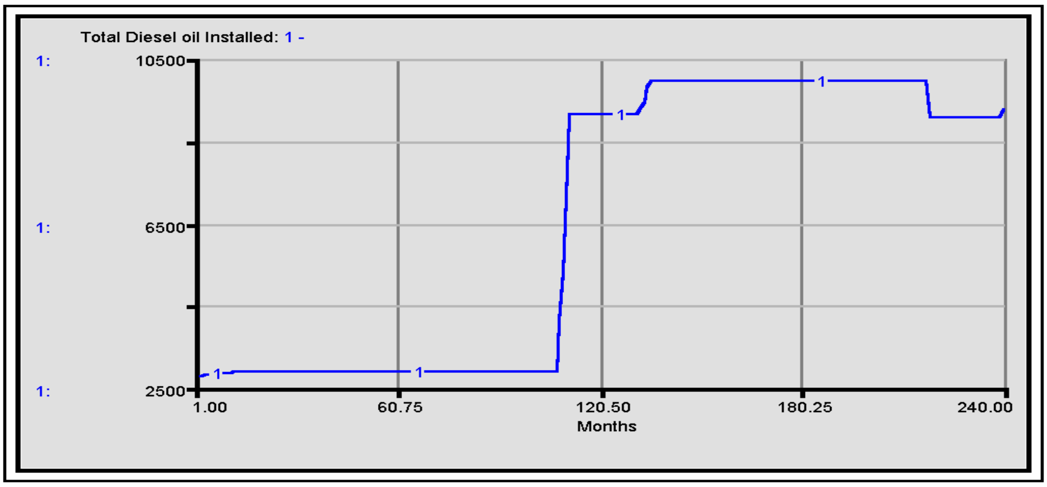


Figure 6.35. The total installed capacity of diesel-oil plants (MW) in the case of very limited imported primary energy resources' reserve

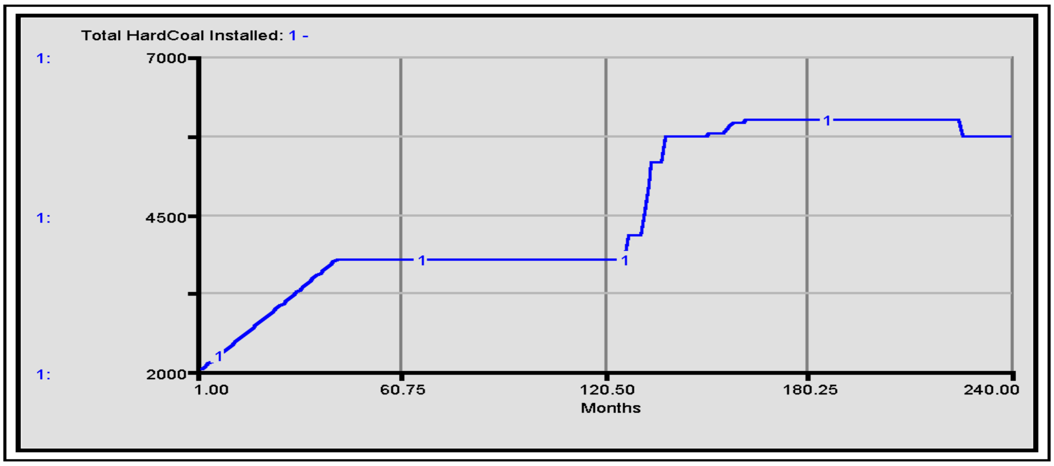


Figure 6.36. The total installed capacity of imported-hard coal power plant capacity (MW) in the case very limited imported primary energy resources' reserve

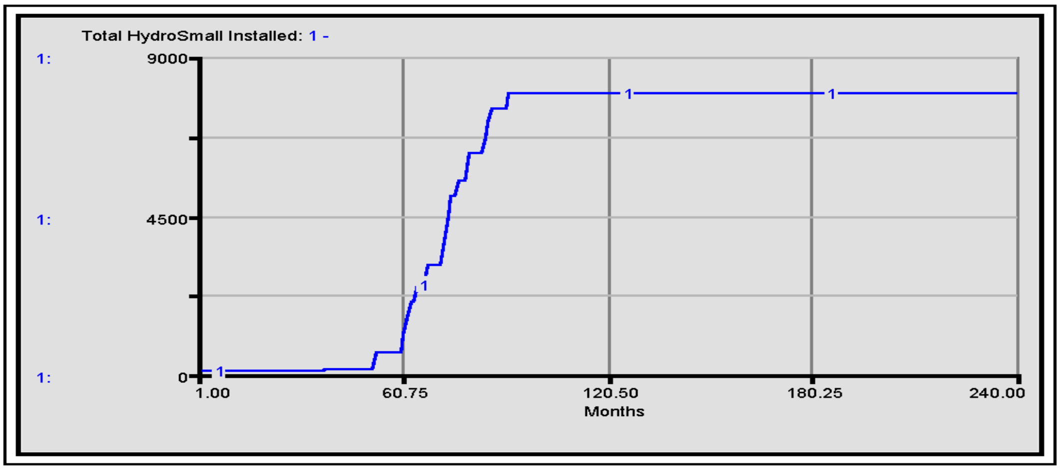


Figure 6.37. The total installed capacity of hydro-small plant capacity (MW) in the case of very limited imported primary energy resources' reserve

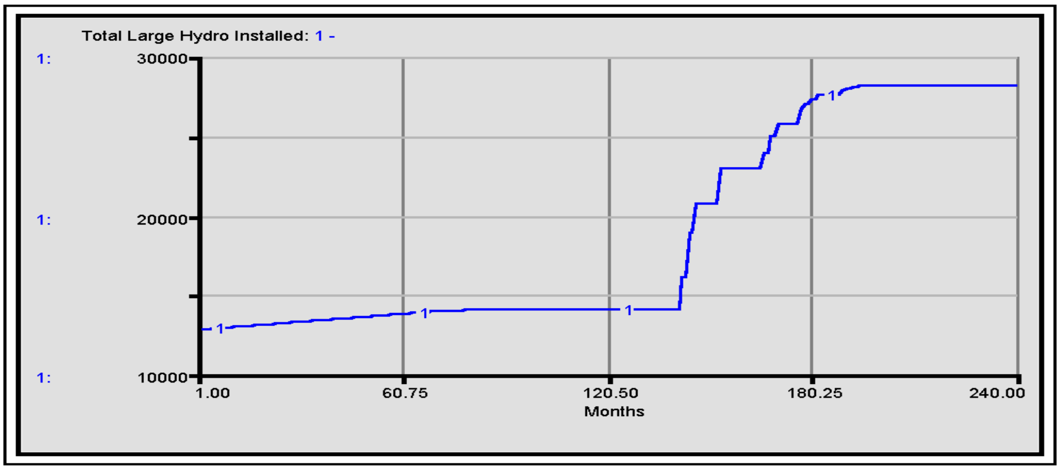


Figure 6.38. The total installed capacity of large-hydro plant capacity (MW) in the case of very limited imported primary energy resources' reserve

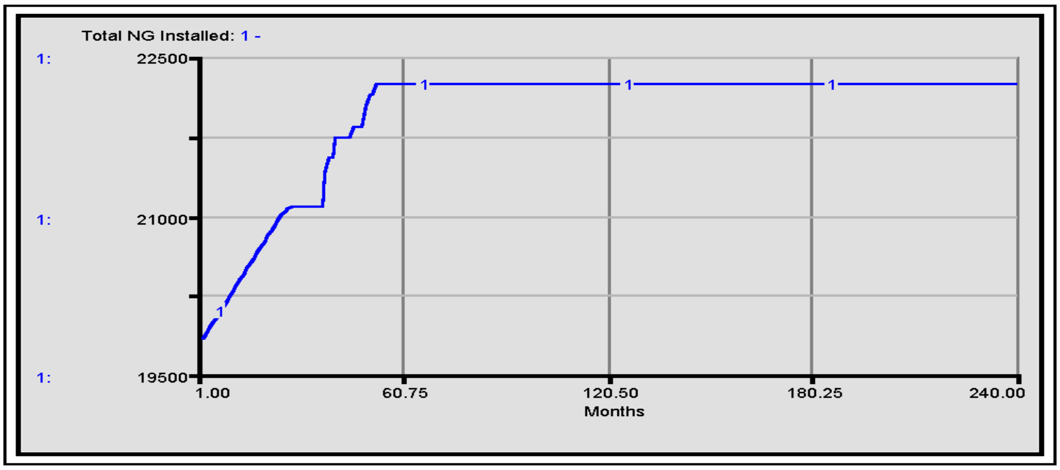


Figure 6.39. The total installed capacity of natural gas power plant capacity (MW) in the case of very limited imported primary energy resources' reserve

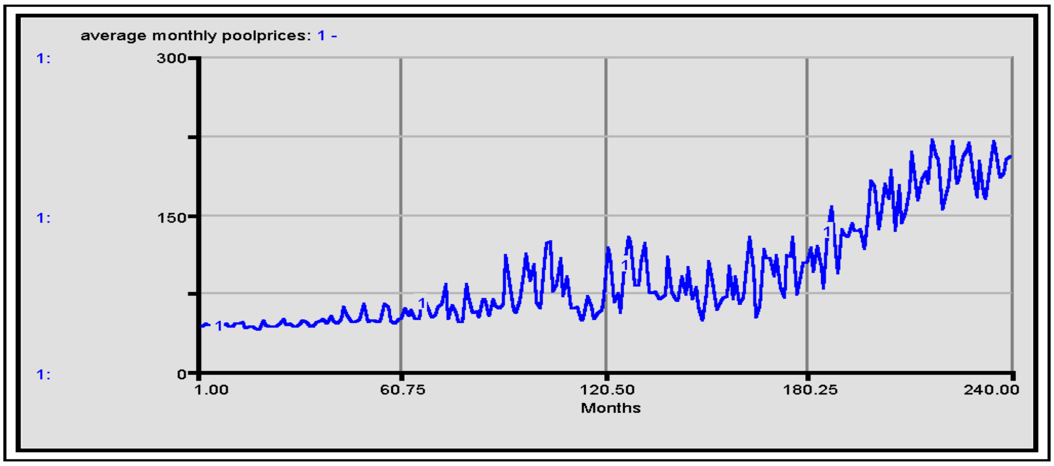


Figure 6.40. The average monthly pool price ($/MWh) in the case of very limited imported primary energy resources' reserve

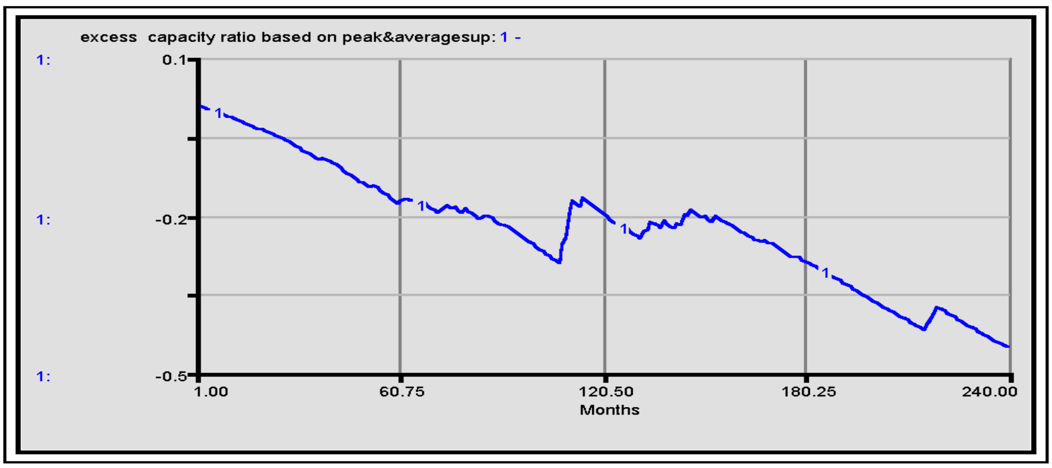


Figure 6.41. The electricity reserve margin (per cent) in the case of very limited imported primary energy resources' reserve

6.2.3.1.5. The Interest Rate on Debt. The sensitivity of the model against the interest rate on debt that is used for financing new investments is studied by setting the interest rate to two extreme values (1 per cent and 100 per cent). The related simulation outputs are given through Figures 6.42-6.48. In the related figures, the 1st and 2nd runs illustrate the cases with 1 per cent and 100 per cent interest rates on debt, respectively.

As the interest rate on debt increases,

i. WACC (weighted average cost of capital, defined in Chapter 5.) and consequently investors' rate of return expectations increases, in other words investors are expected to invest less on power plants. As a consequence, it is expected that total installed capacity at the end of the planning horizon will decrease. This expectation is in line with the simulation output displayed in Figure 6.42.
ii. Furthermore, investors are expected to concentrate on less capital intensive plant types (such as Natural Gas). This expected behavior is observed through Figures 6.43-6.46.
iii. Note that, during the intermediate years, electricity reserve margin in the 2nd run is higher than the value in the 1st run as displayed in Figure 6.47. This is because of the following factors;
    - Investors in the 2nd run, invests more on natural gas plants and less on other plant types;
    - Natural gas plants have low construction times;
    - So, investors' new power plants in the 2nd run are introduced to the market earlier than that of the case in the 1st run.

As explained above, simulation outputs are in line with the expectations under the two extreme cases regarding the interest rate on debt.

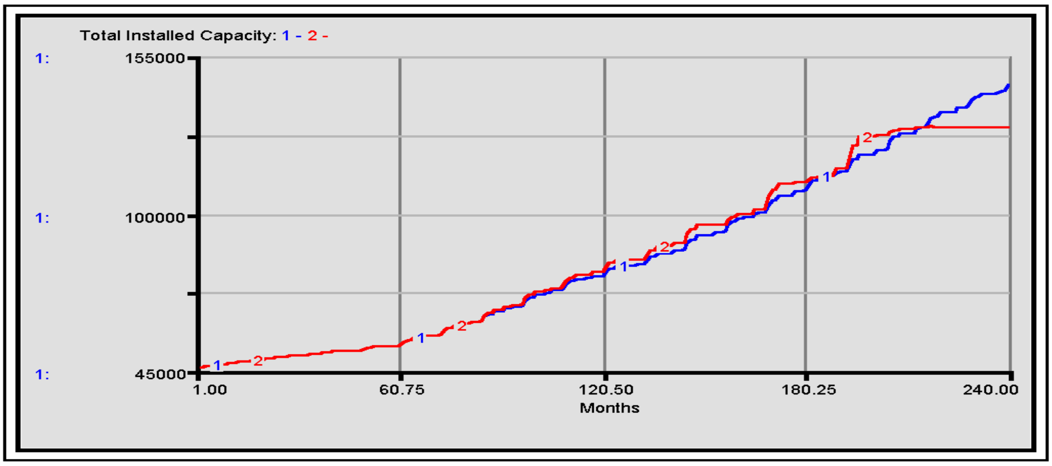


Figure 6.42. Total installed capacity (MW) under extreme debt interest assumptions

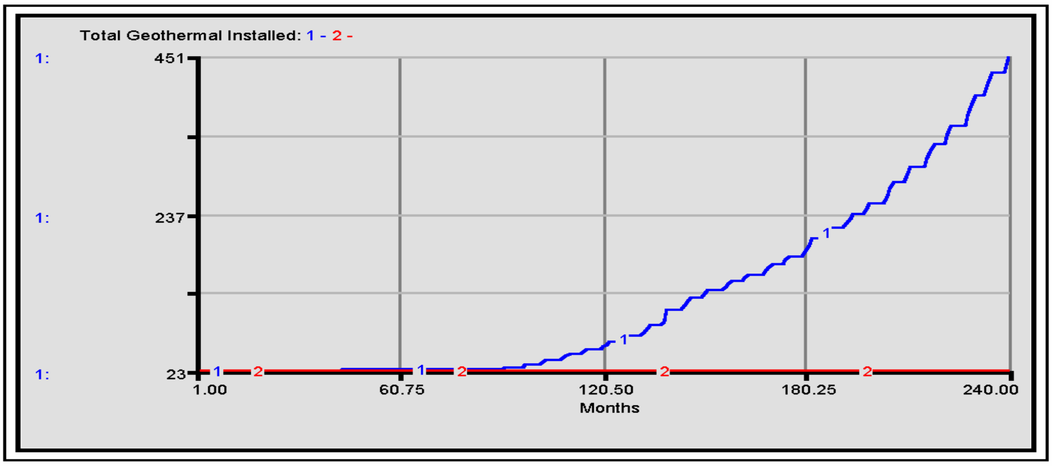


Figure 6.43. Total installed geothermal power plant capacity (MW) under extreme debt interest assumptions

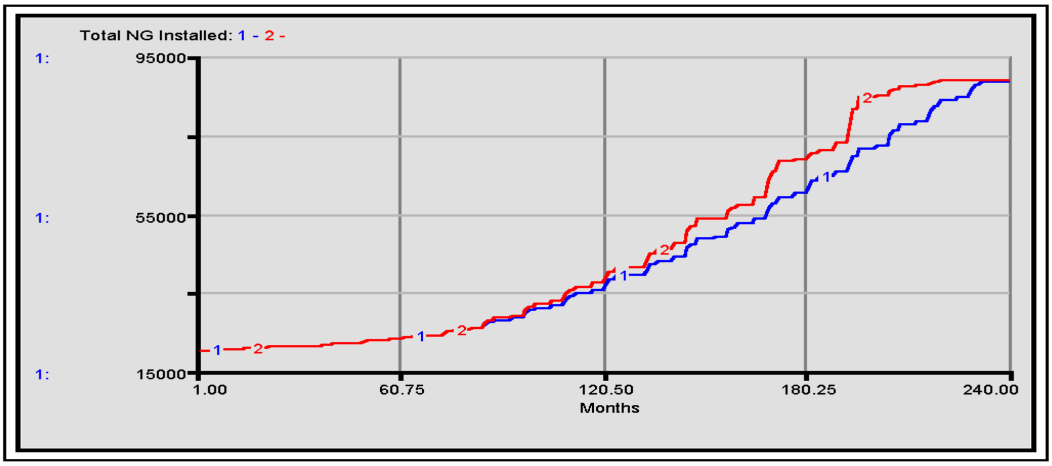


Figure 6.44. Total installed natural gas power plant capacity (MW) under extreme debt interest assumptions

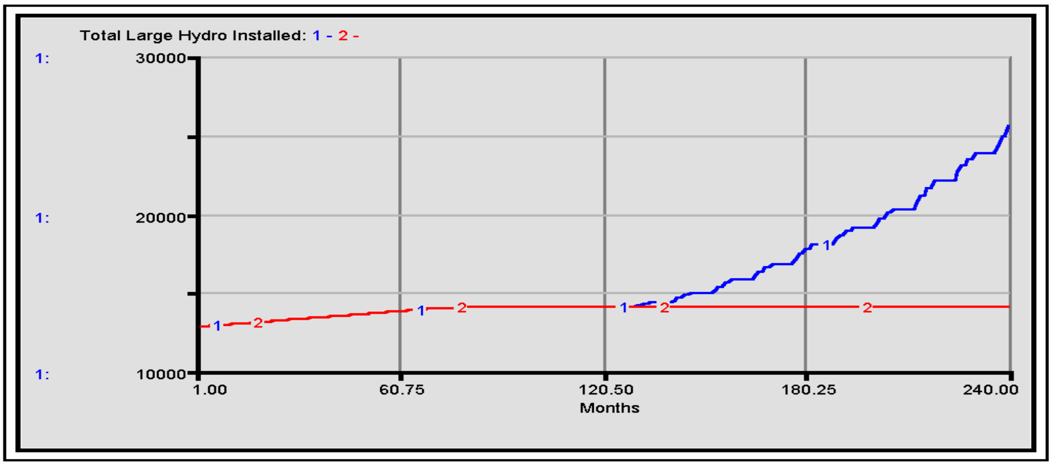


Figure 6.45. Total installed large-hydro power plant capacity (MW) under extreme debt interest assumptions

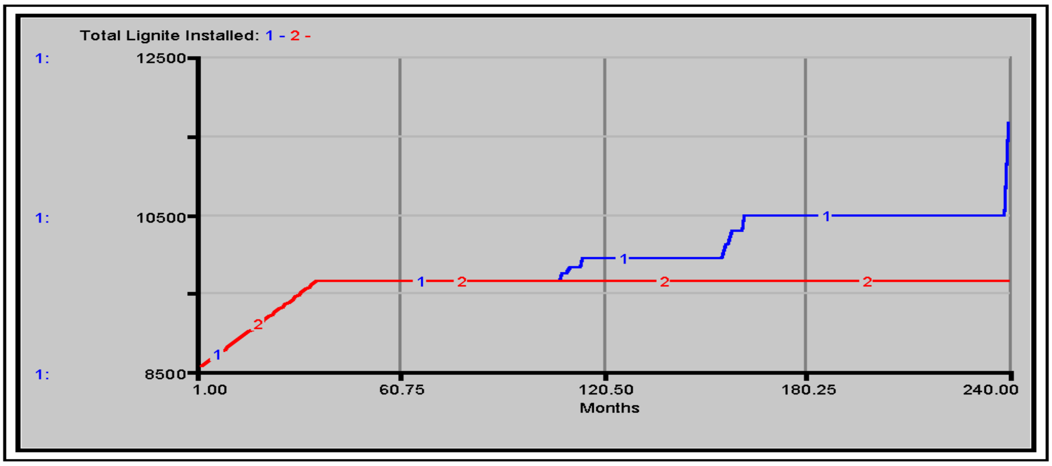


Figure 6.46. Total installed lignite power plant capacity (MW) under extreme debt interest assumptions

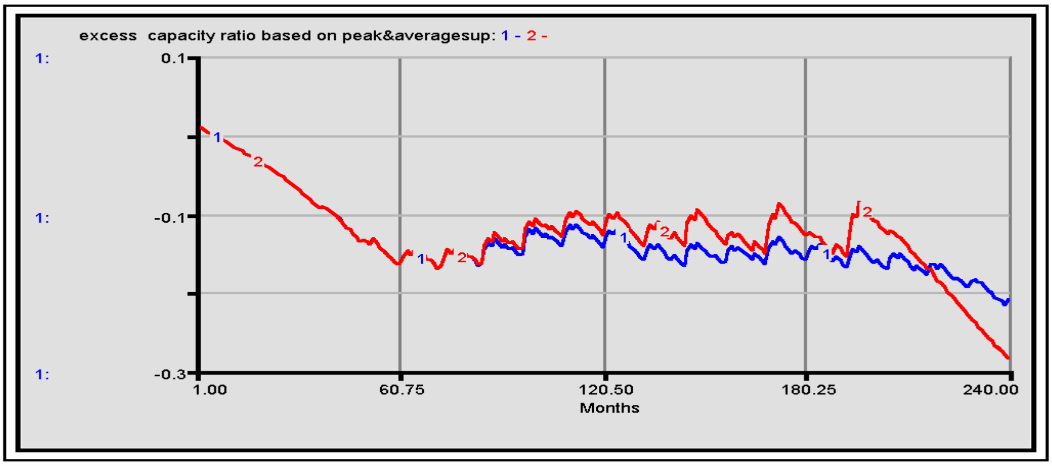


Figure 6.47. Electricity reserve margin (per cent) under extreme debt interest assumptions

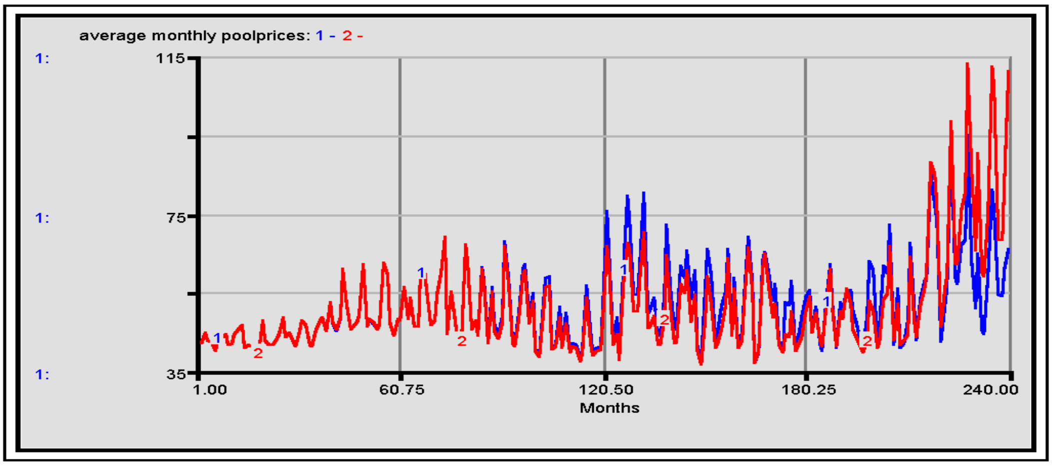


Figure 6.48. Average monthly pool prices ($/MWh) under extreme debt interest assumptions

6.2.3.2. Sensitivity Analysis. In this section, simulation outputs of the model are investigated for the parameters forwarded below, in order to analyze model's sensitivity against these key parameters;

- Three different levels of the VOLL (0, 2000, 4000 $/MWh)
- Four different levels of the CO_2 tax rate (0, 0.006, 0.2, 1 $/kg)
- Four different levels of the debt ratio for a new investment (0, 0.375, 0.75, 1)
- Five different levels for state support for renewable energy (0, 0.225, 0.45, 0.675, 0.9 per cent)
- Five different unit production cost of natural gas power plants 30, 60, 90, 120, 150 $/MWh.

Actually, detailed analysis of the last two parameters is given in detail in Chapter 7.

6.2.3.2.1. The VOLL. The sensitivity of the model regarding the VOLL is studied by setting the VOLL to three different levels (0, 2000, 4000 $/MWh). Throughout Figures 6.49-6.55, the 1st, 2nd and 3rd runs illustrate the cases with zero, 2000 and 4000 $/MWh VOLL, respectively.

As the VOLL increases, the following behaviors are expected and observed during the sensitivity analysis;

i. Average monthly pool price is expected to increase, in line with the simulation outputs depicted in Figure 6.54.
ii. Electricity reserve margin is expected to increase, in line with the simulation outputs depicted in Figure 6.55.
iii. Owing to the increased price, highly capital intensive plants become attractive and total installed capacity increases, as the simulation outputs depicted through Figure 6.49-Figure 6.53.

Note that; in case VOLL is zero, investors invest only on small-hydro plants (having low investment and variable cost) and after utilizing all the small-hydro potential of the country, they do not invest on any other power plant types.

As briefly discussed above, simulation outputs are sensitive to VOLL in the same way as the electricity market based on the pool system is.

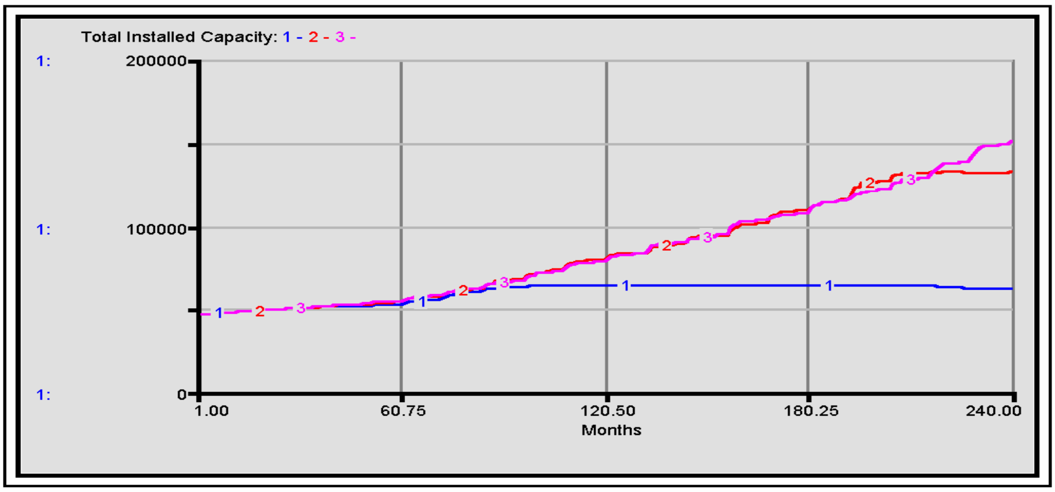


Figure 6.49. Total installed capacity (MW) under different VOLL values

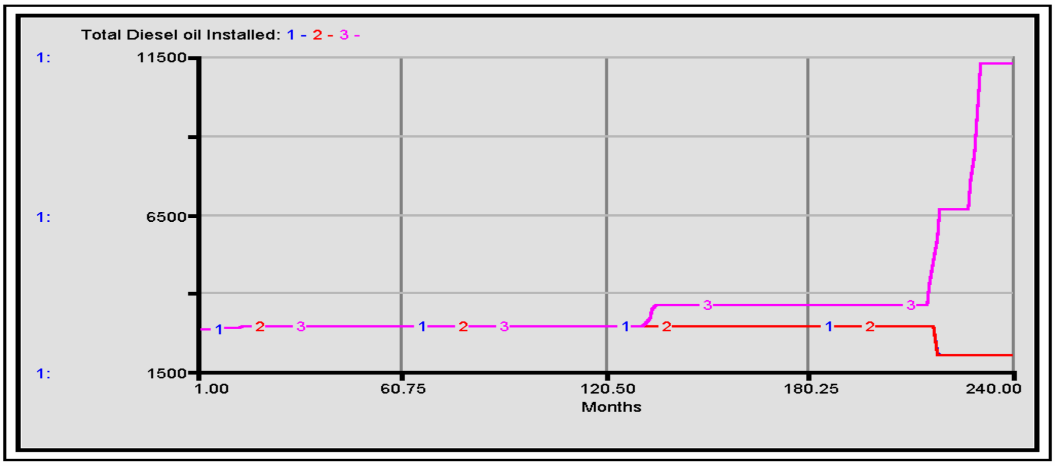


Figure 6.50. Total installed capacity of diesel-oil power plant (MW) under different VOLL values

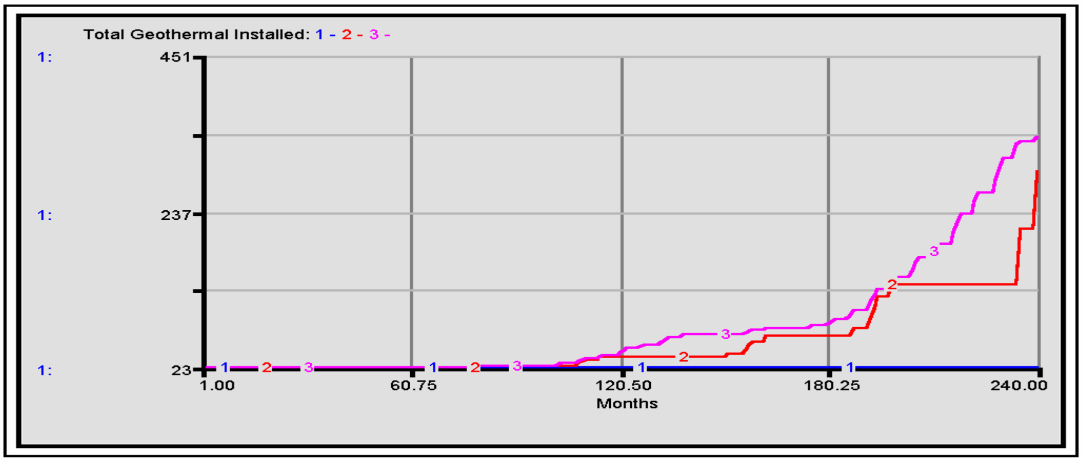


Figure 6.51. Total installed capacity of geothermal power plant (MW) under different VOLL values

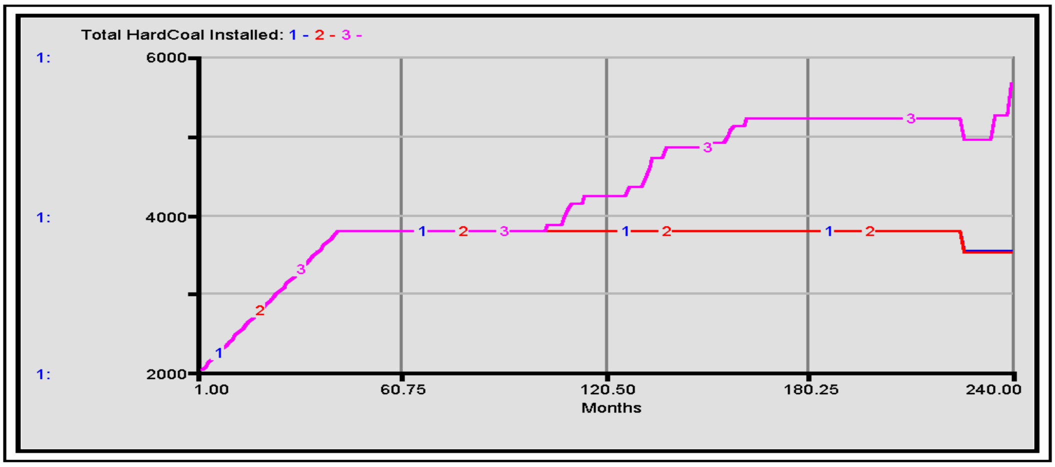


Figure 6.52. Total installed capacity of imported-hard coal power plant (MW) under different VOLL values

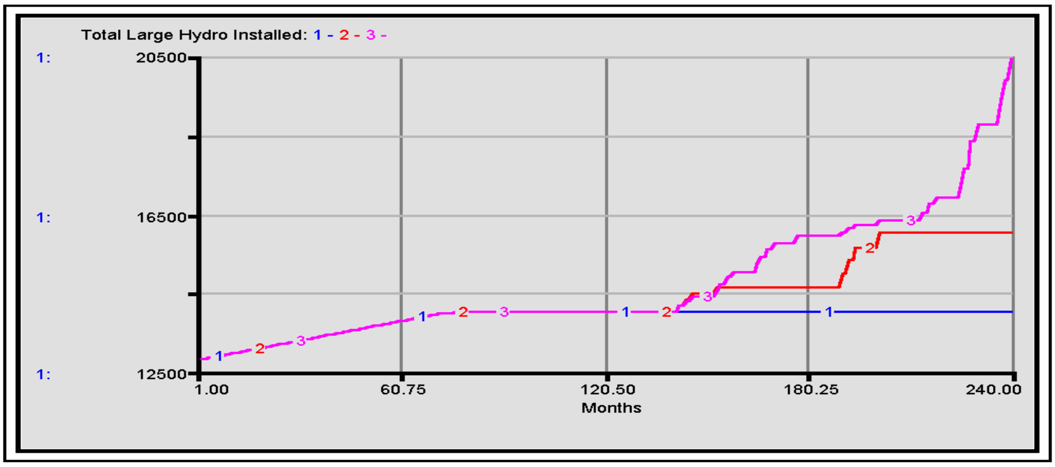


Figure 6.53. Total installed capacity of large-hydro power plant (MW) under different VOLL values

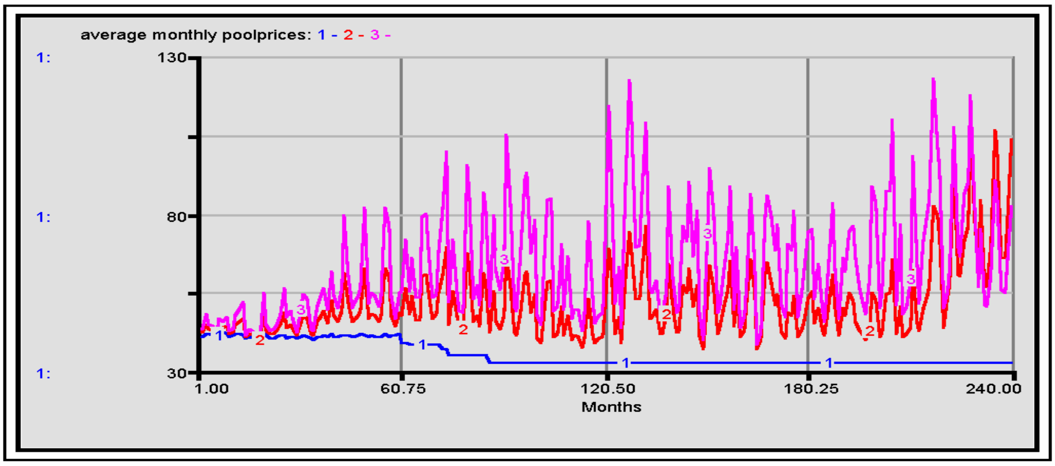


Figure 6.54. Average monthly pool price($/MWh) under different VOLL values

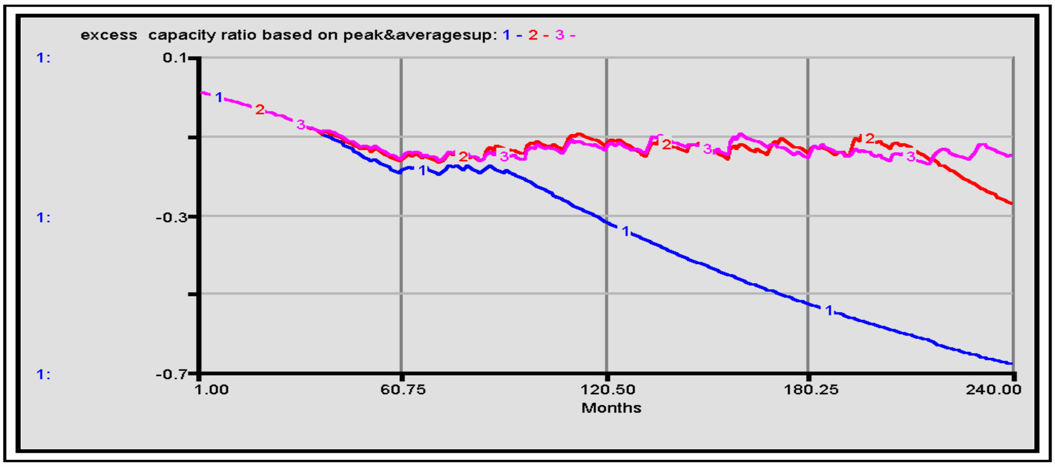


Figure 6.55. Reserve margin (per cent) under different VOLL values

6.2.3.2.2. The CO_2 Tax. In this section, the sensitivity of the model regarding different levels of the CO_2 tax (0, 0.006, 0.2 and 1 $/kg) is analyzed. Throughout Figures 6.56-6.63, the 1st, 2nd,3rd and 4th runs illustrate the cases with zero, 0.006, 0.2 and 1 \$/kg CO_2 tax, respectively.

As the CO_2 tax increases, the following behaviors are expected and observed during the sensitivity analysis;

i. The majority of investors' initial plant portfolio consists of thermal plants. Therefore, as the CO_2 tax increases, pool price is expected to increase distinctly as observed in Figure 6.62.

ii. Investors are expected to invest more on renewable power plants and less on thermal power plants. This expected behavior is in line with the simulation outputs presented in Figures 6.57.-6.61 and Figure 6.63. On the other hand, the simulated behavior of small-hydro and diesel-oil power plants, are somewhat against expectation; outputs suggest that investment on hydro and diesel-oil power plants are insensitive to the CO_2 tax. Investors invest on small hydro power plants during the first half of the planning horizon, and they do not invest on diesel oil plants regardless of the CO_2 tax.

iii. Investors perceive the electricity market with higher pool prices more attractive. Due to this reason, total installed capacity is expected to be highest in the 4th run since average monthly pool prices in the 4th scenario are higher than those of the cases in the other three scenarios, as it is presented in Figure 6.62. This expectation is in line with the simulation outputs displayed in Figure 6.56.

As explained above, the CO_2 tax is observed to have important effects on the mixture of the power plants in the market, as expected.

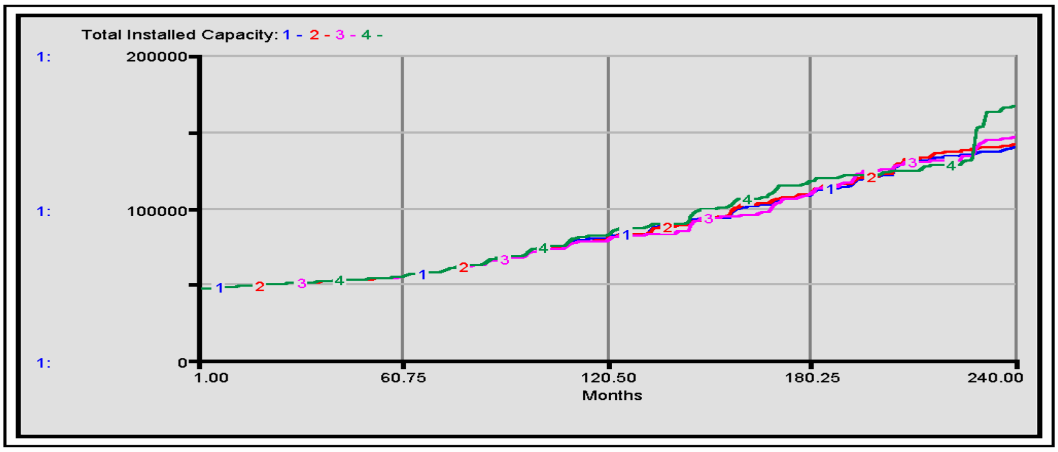


Figure 6.56. Total installed capacity (MW) under different CO_2 tax levels

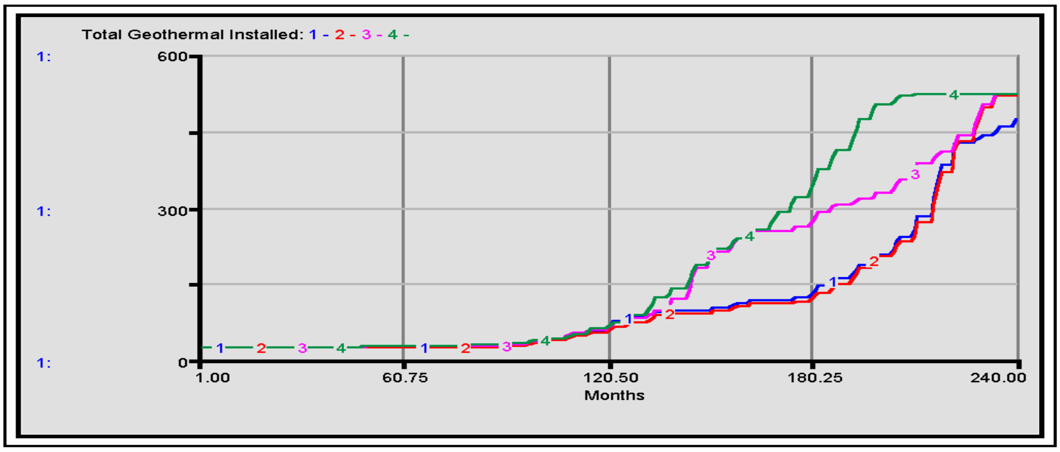


Figure 6.57. Total installed capacity of geothermal plant (MW) under different CO_2 tax levels

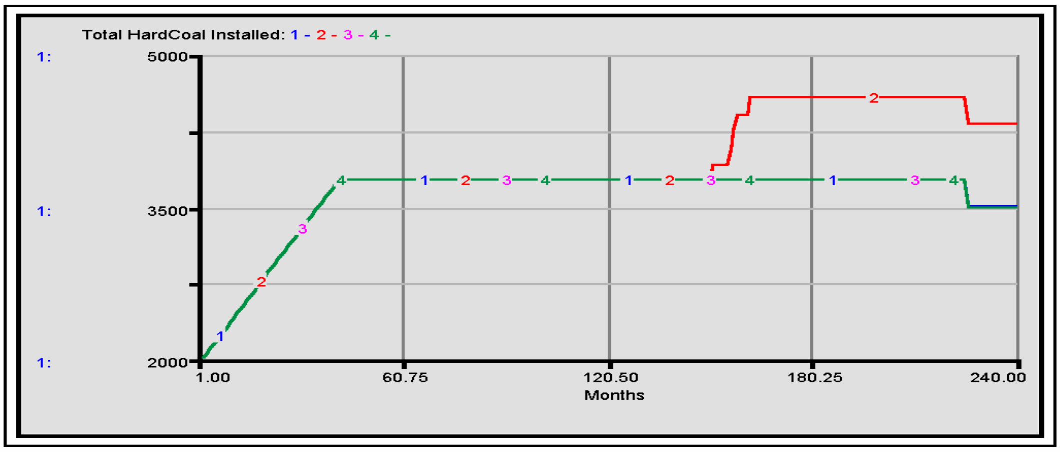


Figure 6.58. Total installed imported-hard coal plant capacity (MW) under different CO_2 tax levels

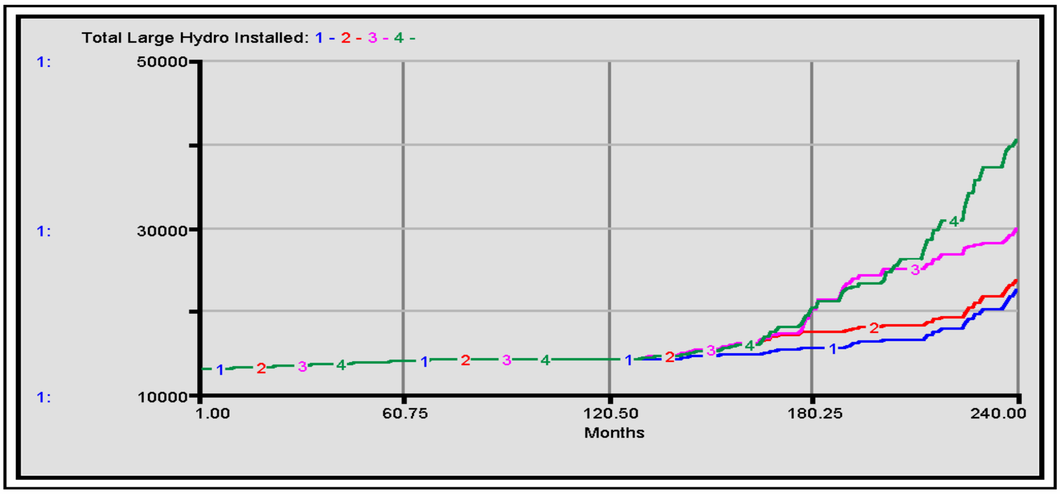


Figure 6.59. Total installed capacity of large-hydro plant (MW) under different CO_2 tax

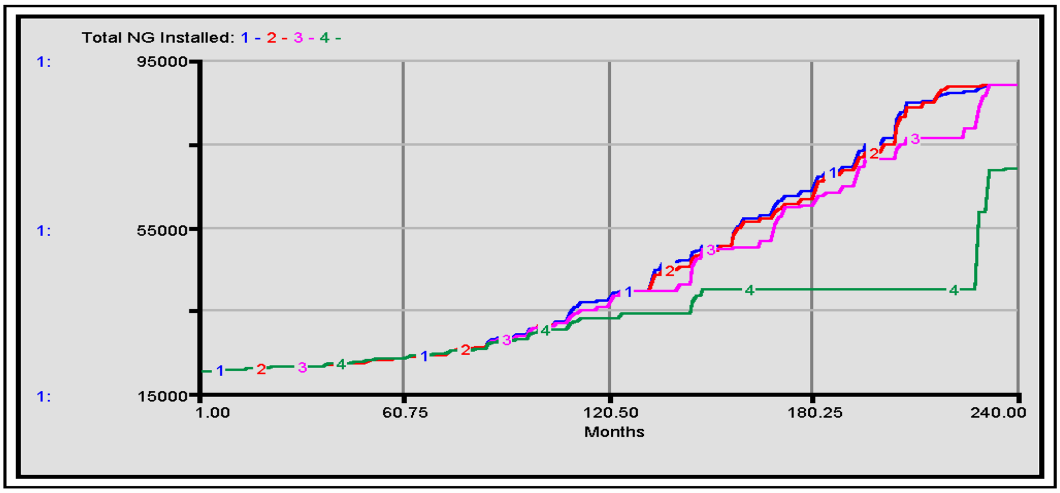


Figure 6.60. Total installed capacity of natural gas plant (MW) under different CO_2 tax

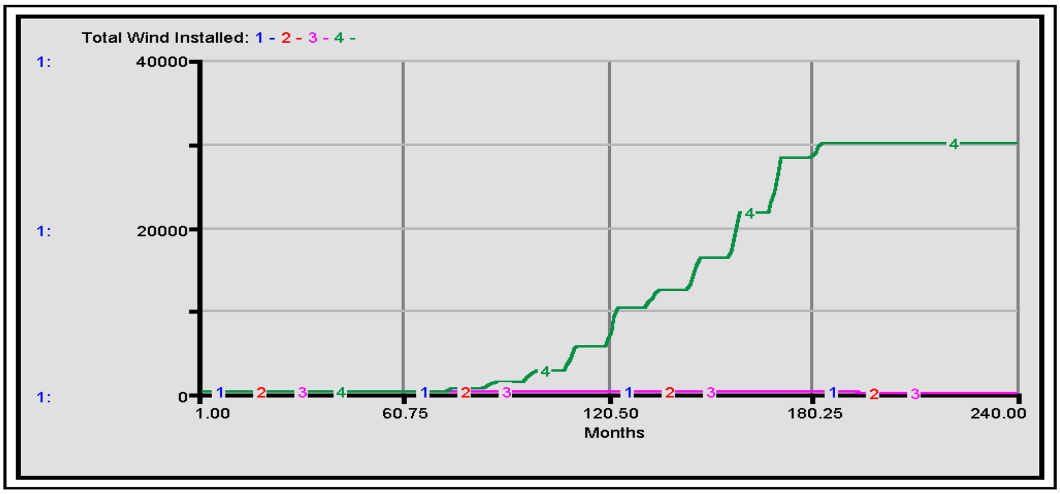


Figure 6.61. Total installed capacity of wind plant (MW) under different CO_2 tax

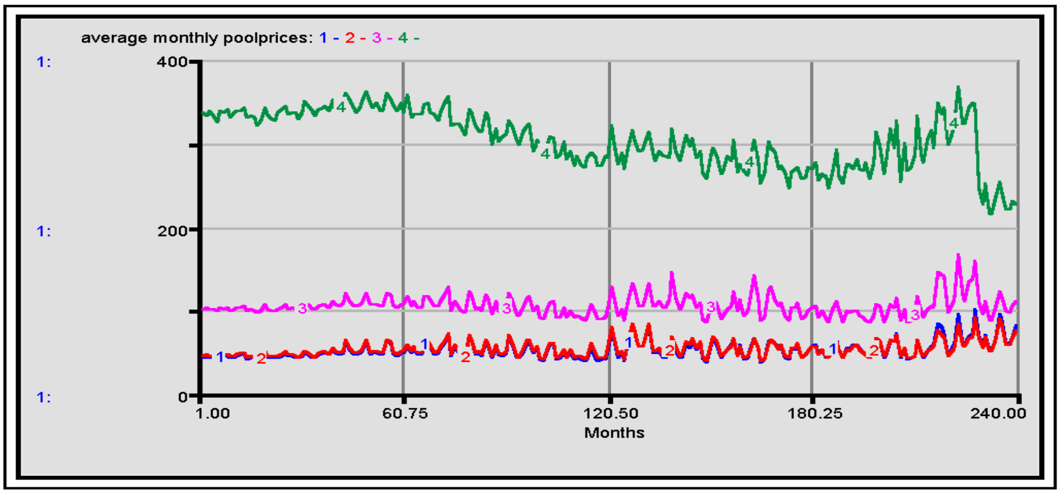


Figure 6.62. Average monthly pool price ($/MWh) under different CO_2 tax

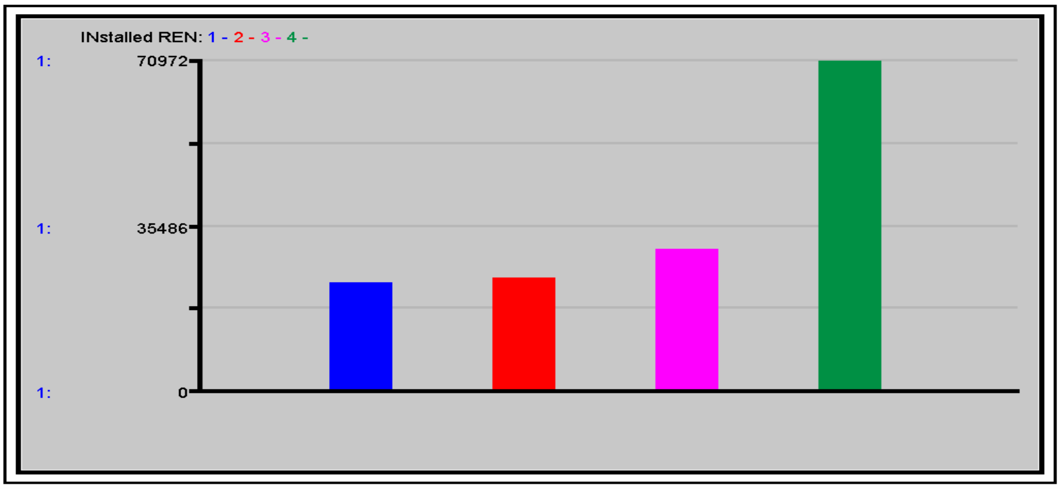


Figure 6.63. Total installed capacity of renewable plants(MW), at the end of the planning horizon, under different CO_2 tax

6.2.3.2.3. The Debt Ratio. The sensitivity of the model regarding the debt ratio in new investment is studied by setting this ratio to four different levels (0, 0.375, 0.75, 1). Throughout Figures 6.64-6.68, the 1st, 2nd, 3rd and 4th runs illustrate the cases with zero, 0.375, 0.75 and 1 debt ratio, respectively.

Debt financing is less expensive than equity financing, because of tax exemptions associated with the financial costs (interest payments) of debt. Due to this reason, as can be observed from Equation 5.9, WACC decreases as debt ratio of a new investment increases. Consequently, rate of return expectations of the investors from new investments decreases, as debt ratio of a new investment increases.

On the other hand, investors' liquid funds do not suffice to cover all the investment costs of capital intensive power plants. Therefore, investors can afford to invest more in new power plants, as the debt ratio of a new investment increases. The effect of debt ratio is extensively investigated in Chapter 7.

Due to the reasons forwarded previously, total installed capacity in the market is expected to increase as debt ratio of a new investment increases. This expectation is in line with the simulation outputs displayed in Figure 6.64. Additionally, investors are expected to invest more on power plants with high investment but low unit production costs (geothermal, large hydropower, lignite power plants), whereas they invest less on power plant types with low investment but high unit production costs (natural gas power plants). This expectation is parallel to the simulation outputs displayed through Figures 6.65-6.68. Additionally, since small-hydro power plants have low investment and unit production costs, investors continue investing on small-hydro power plants, as long as country's resource potential allows them, regardless of debt ratio. On the other hand, as diesel-oil power plants have high investment and unit production costs, investors do not invest on diesel-oil power plants, no matter what debt ratio is.

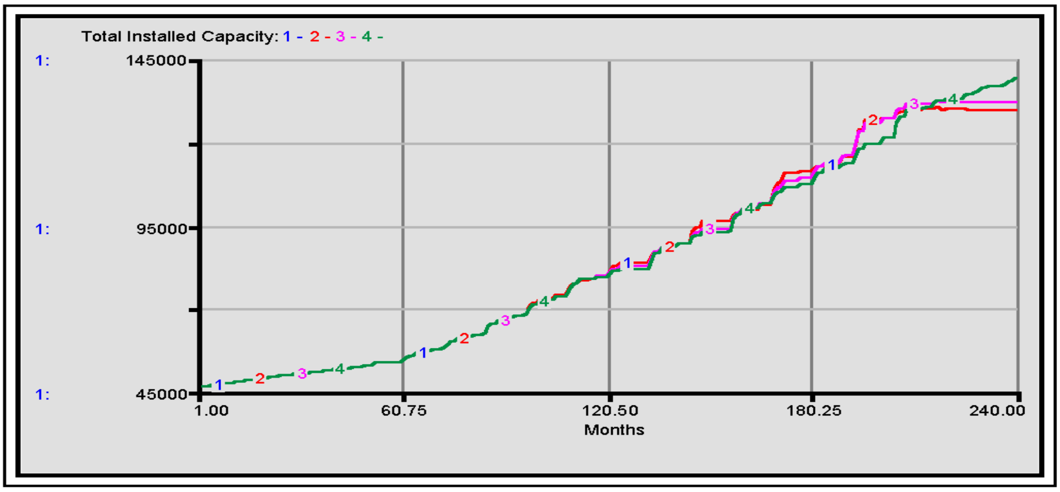


Figure 6.64. Total installed capacity (MW) under different debt ratios

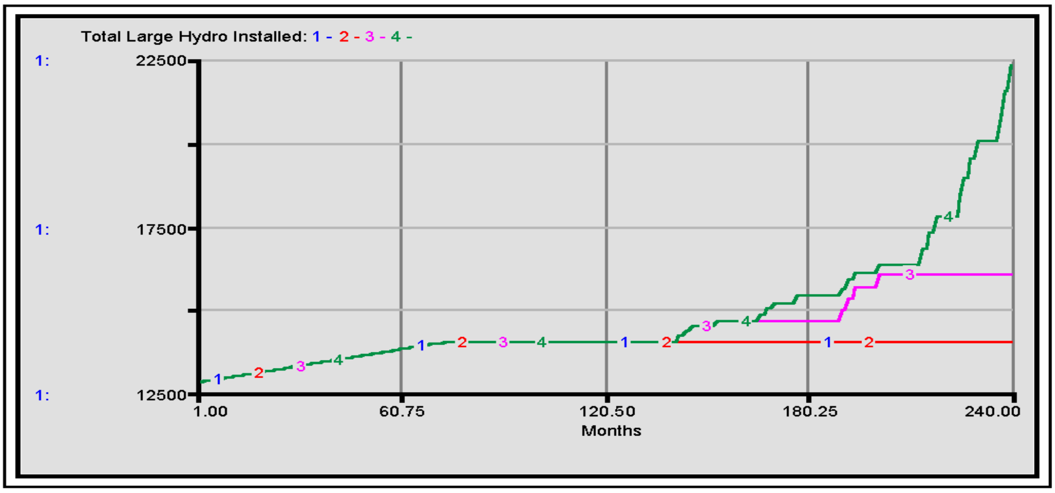


Figure 6.65. Total installed capacity (MW) of large-hydro power under different debt ratios

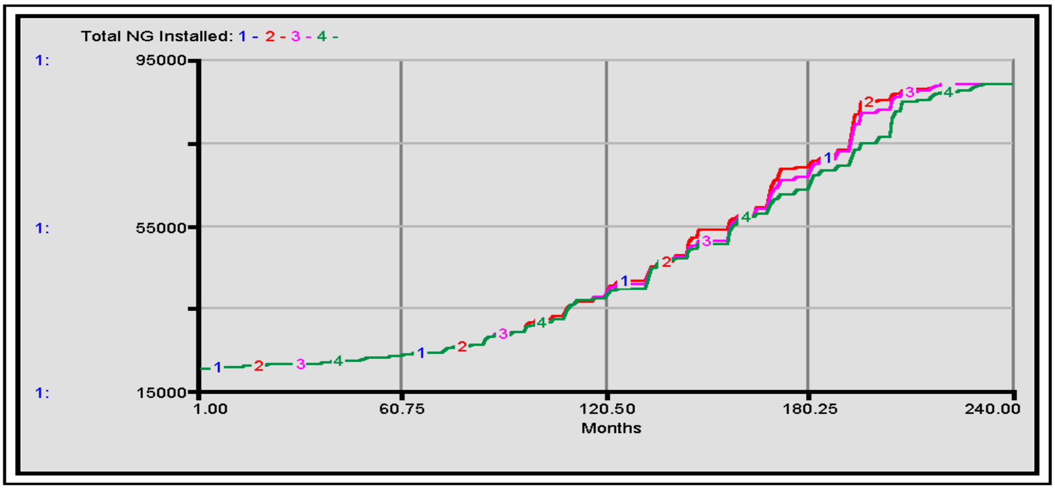


Figure 6.66.Total installed capacity (MW) of natural gas plant under different debt ratios

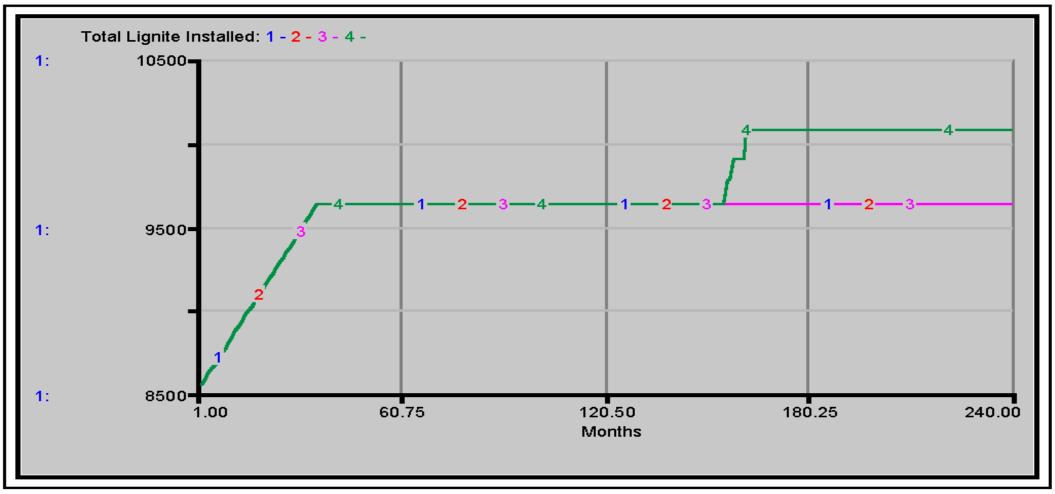


Figure 6.67.Total installed capacity (MW) of lignite power plant under different debt ratios

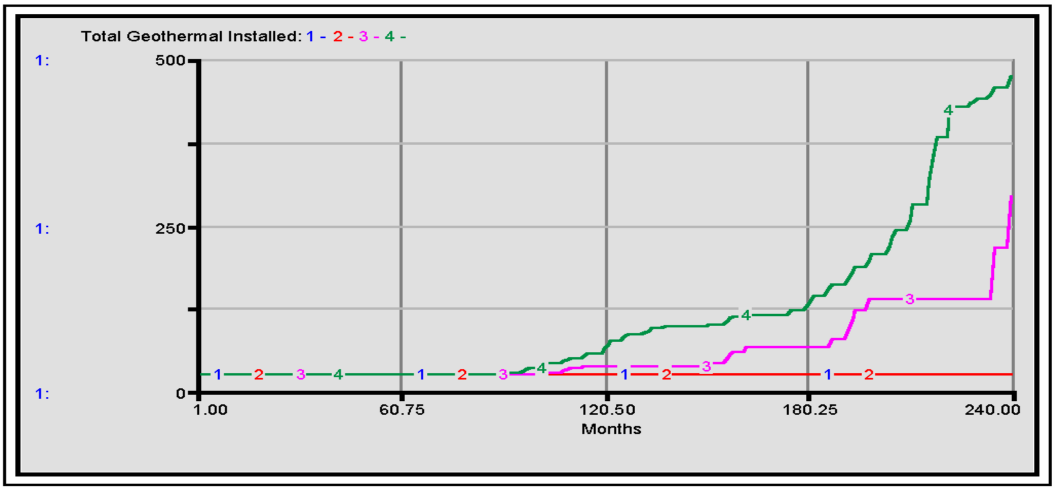


Figure 6.68. Total installed capacity (MW) of geothermal plant under different debt ratios

6.2.3.2.4. The State Support for Renewable Energy. The sensitivity of the model regarding the level of renewable support has been studied by setting the state support for the renewable energy parameter to five different values (0, 0.225, 0.45, 0.675, 0.9). Throughout Figures 6.69-6.75, the 1st, 2nd, 3rd, 4th and 5th runs illustrate the cases with zero, 0.225, 0.45, 0.675, 0.9 state support for renewable energy, respectively.

Total installed capacity and total installed renewable power plant capacity is expected to increase as the state support for renewable energy increases. The simulation outputs presented through Figures 6.69-6.84 are in line with this expectation. Besides, as renewable power plants become more attractive (as the state support increases). Investments on thermal power plants decrease as observed in natural gas plant case displayed in Figure 6.73.

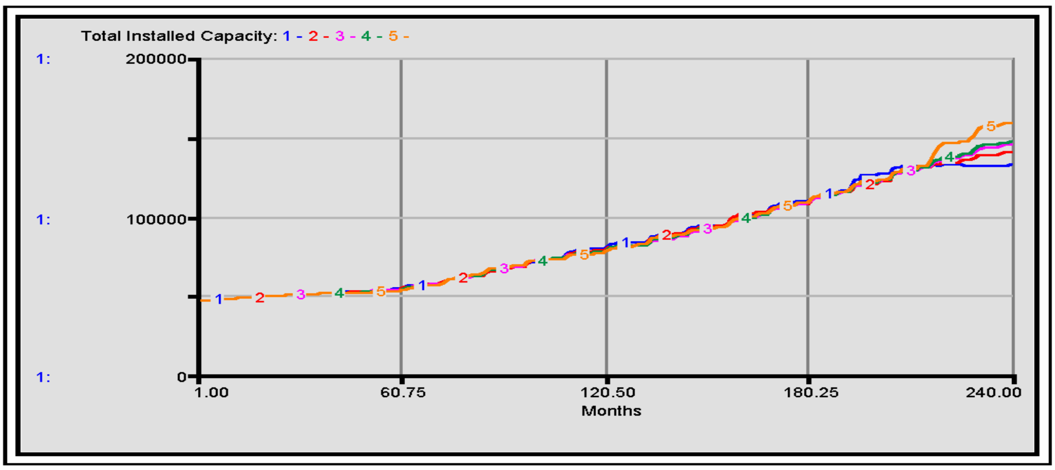


Figure 6.69. Total installed capacity (MW) under different levels of state support for renewable energy

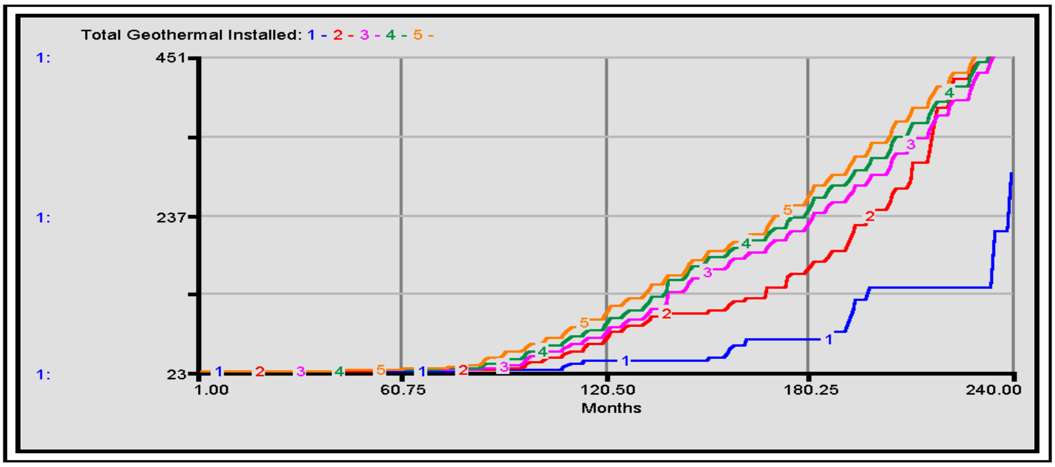


Figure 6.70. Total installed capacity (MW) of geothermal plant under different levels of state support for renewable energy

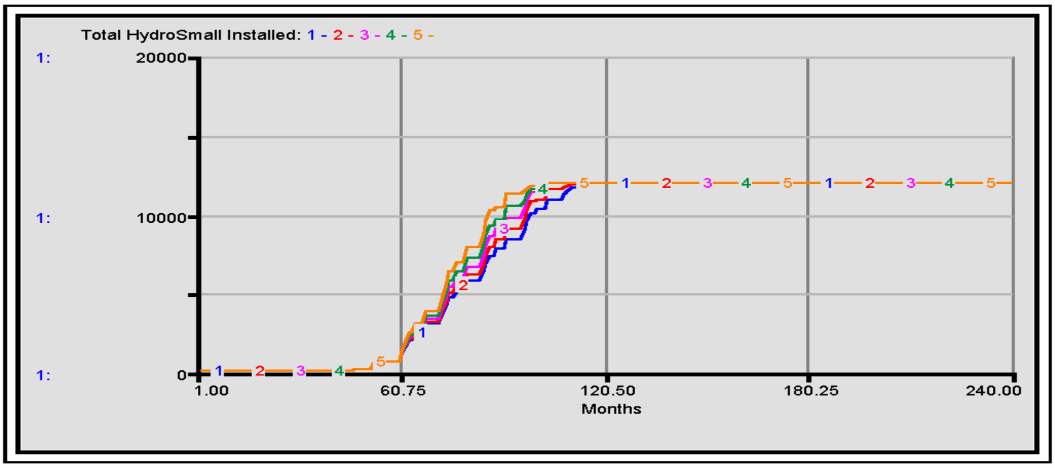


Figure 6.71. Total installed capacity (MW) of small-hydro plant under different levels of state support for renewable energy

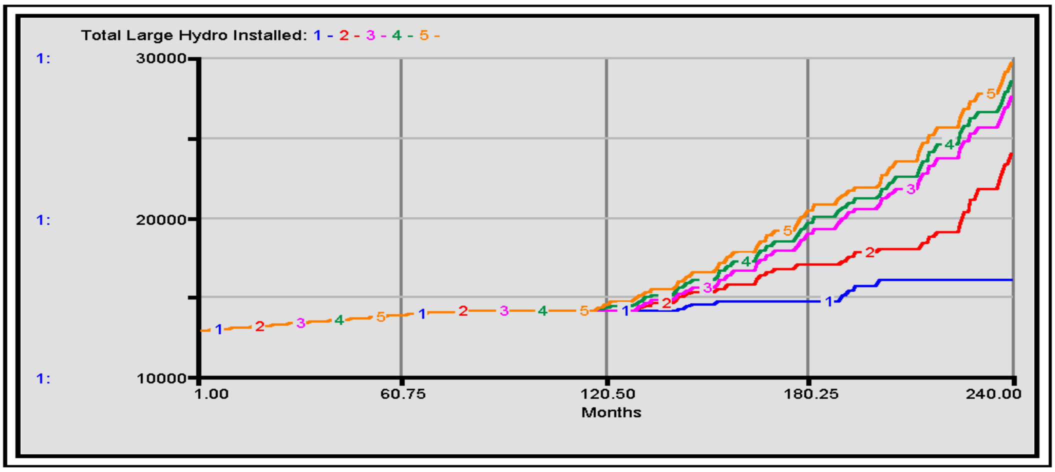


Figure 6.72. Total installed capacity (MW) of large-hydro plant under different levels of state support for renewable energy

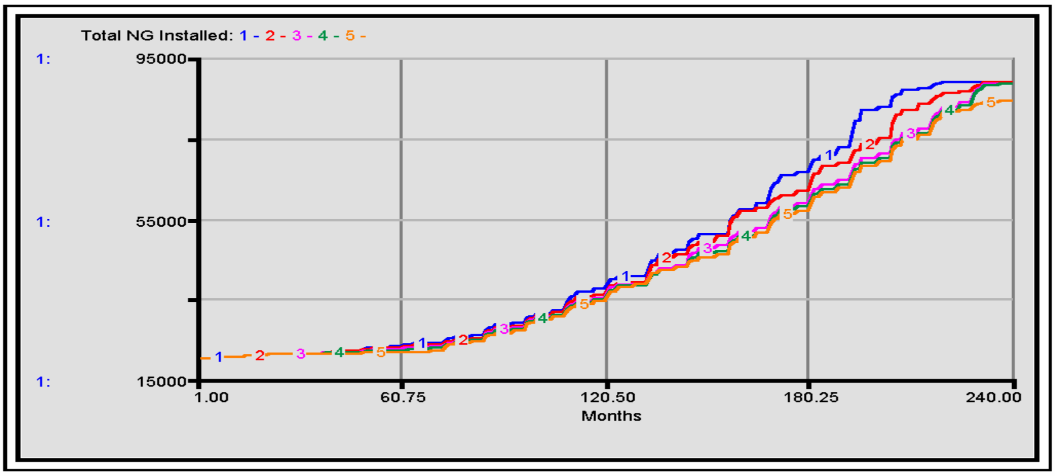


Figure 6.73. Total installed capacity (MW) of natural gas plant under different levels of state support for renewable energy

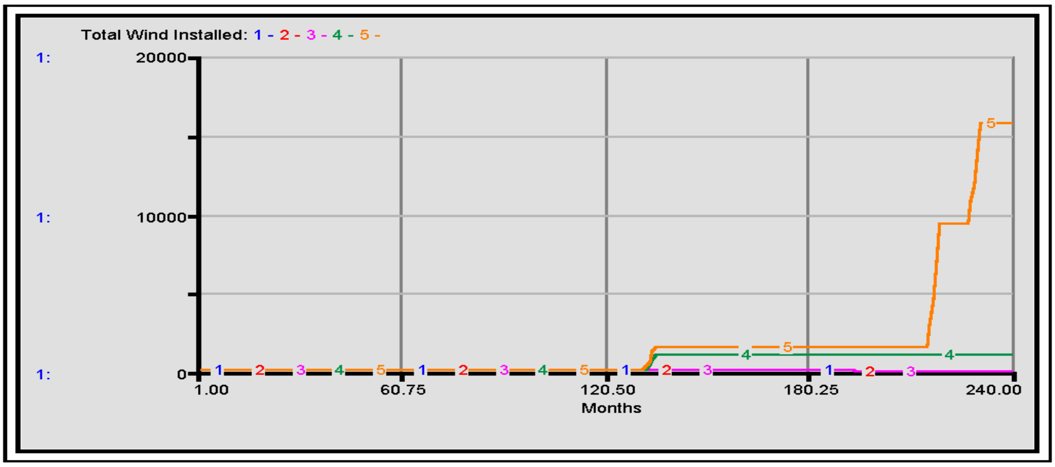


Figure 6.74. Total installed capacity (MW) of wind plant under different levels of state support for renewable energy

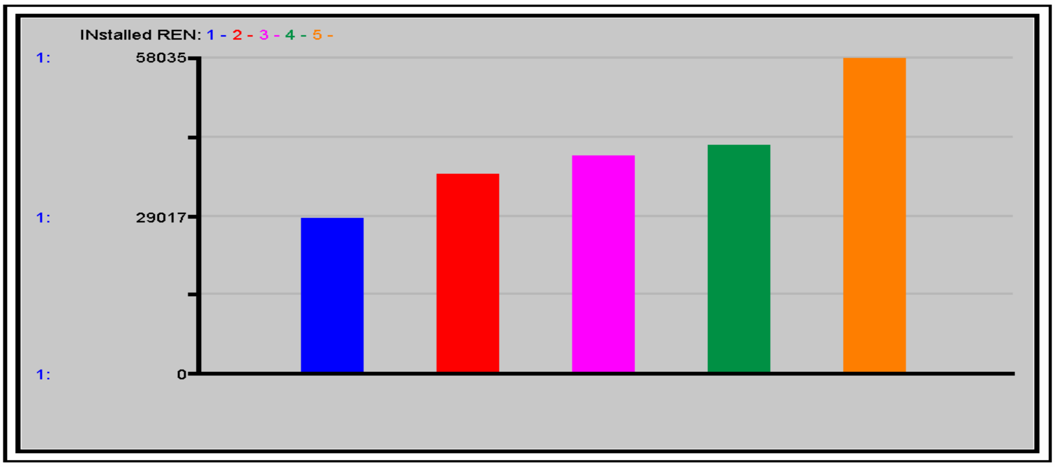


Figure 6.75. Total installed renewable plant capacity (MW), at the end of planning horizon, under different levels of state support for renewable energy

<u>6.2.3.2.5. Unit Production Cost for Natural Gas Power Plants.</u> Recently, there has been a tendency for constructing natural gas power plant owing to its shorter construction time, lower investment cost, unit production cost and CO_2 emissions, in comparison to the other thermal power plant types. Due to this reason, the sensitivity of the model regarding the unit production cost of natural gas plants has been studied by setting the unit production cost to five different levels; 30, 60, 90, 120, 150 \$/MWh in the 1st, 2nd, 3rd, 4th and 5th runs, respectively.

As a major part of the current power plant portfolio in the market is natural gas power plants, pool prices are expected to drastically increase as unit production cost of the natural gas power plants increases. On the other hand, the resulting high pool prices are expected to make some of the other plant types, (which were perceived as unattractive in the base scenario) attractive for the investors. Consequently, in the cases with higher unit production cost of natural gas plants, total installed capacity is expected to be higher.

The simulation outputs given through Figures 6.76- 6.84 are in line with the expectations mentioned above.

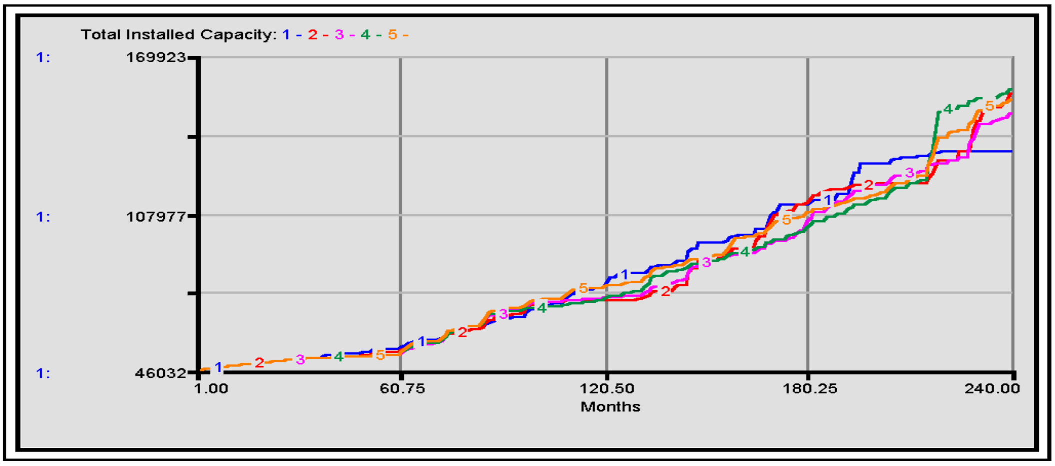


Figure 6.76. Total installed capacity (MW) under different unit production cost of natural gas plants

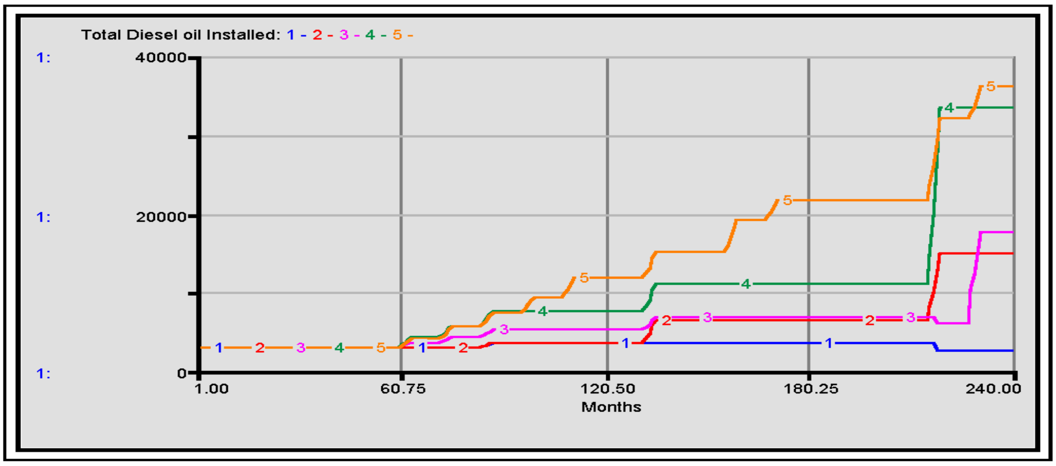


Figure 6.77. Total installed diesel-oil plant capacity (MW) under different unit production cost of natural gas plants

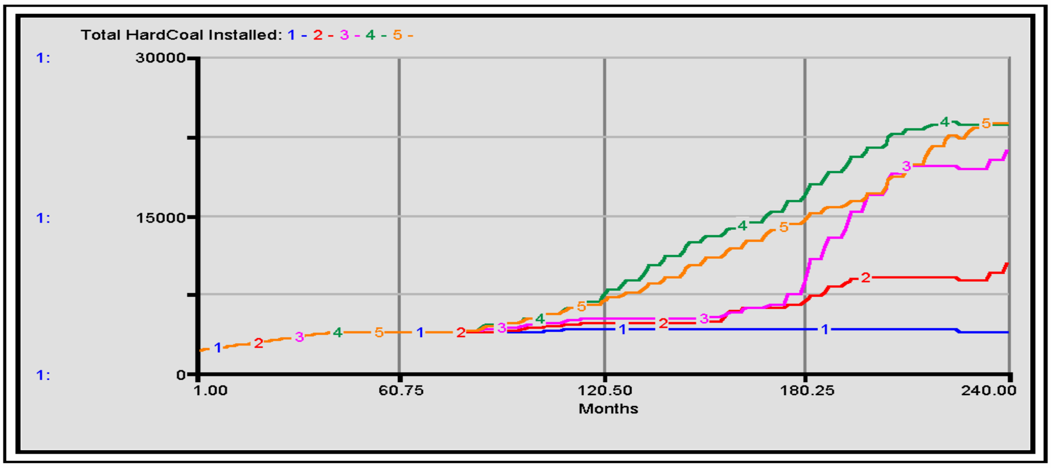


Figure 6.78. Total installed imported-hard coal plant capacity (MW) under different unit production cost of natural gas plants

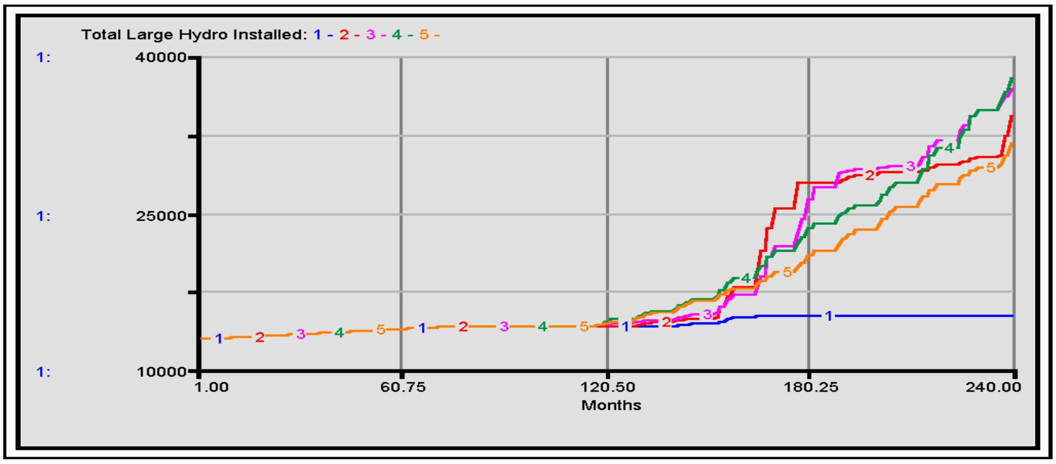


Figure 6.79. Total installed large-hydro plant capacity (MW) under different unit production cost of natural gas plants

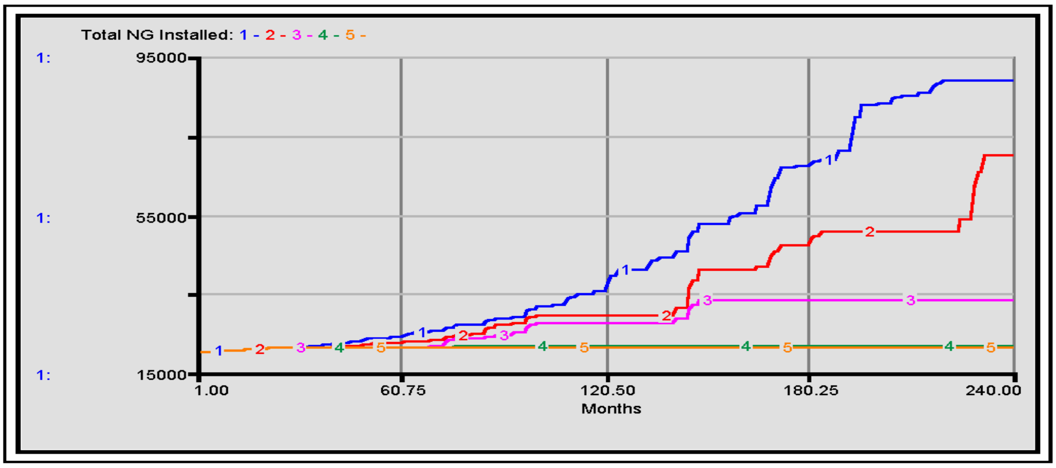


Figure 6.80. Total installed natural gas plant capacity (MW) under different unit production cost of natural gas plants

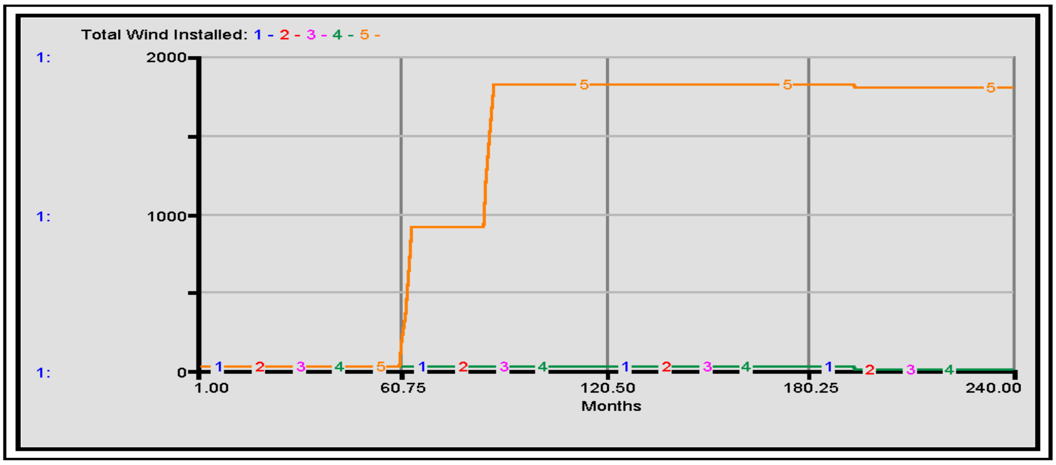


Figure 6.81. Total installed wind plant capacity (MW) under different unit production cost of natural gas plants

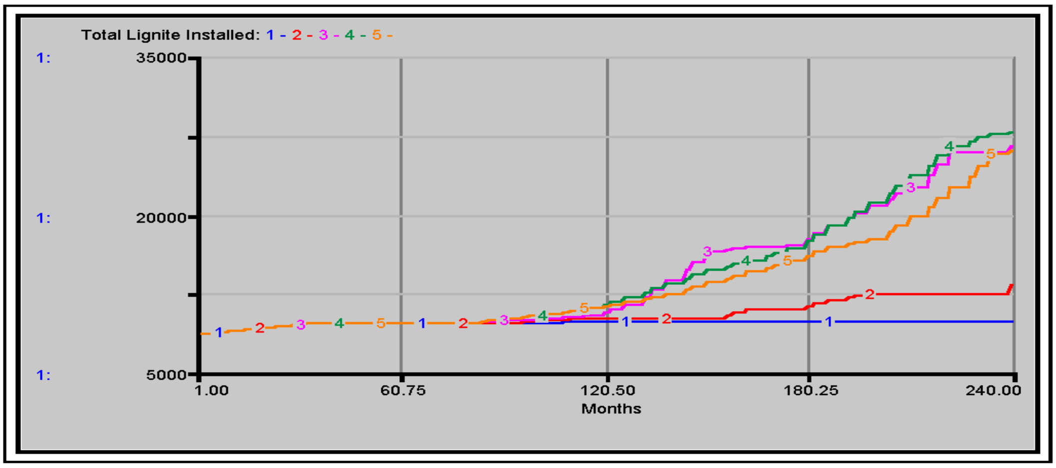


Figure 6.82. Total installed lignite plant capacity (MW) under different unit production cost of natural gas plants

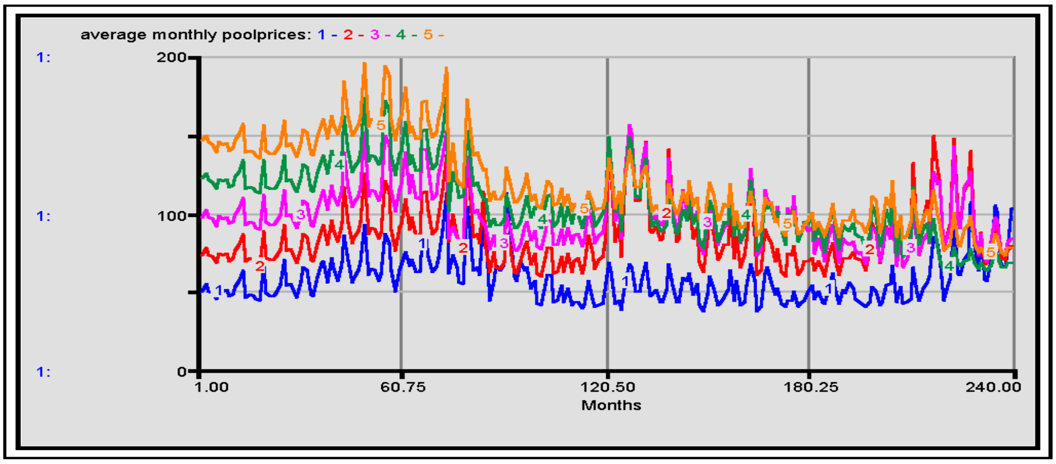


Figure 6.83. Average monthly pool prices ($/MWh)

under different unit production cost of natural gas plants

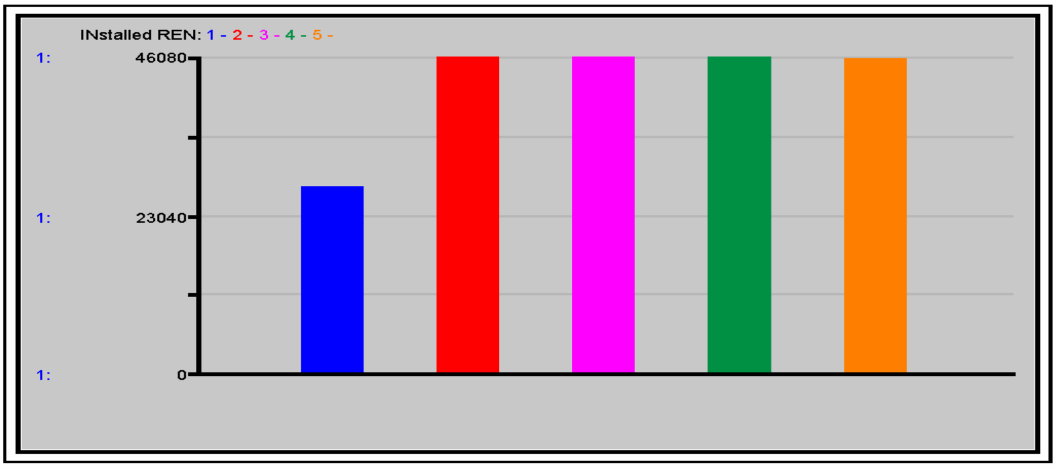


Figure 6.84. Total installed renewable plant capacity (MW), at the end of planning horizon, under different unit production cost of natural gas plants

6.2.4. Remarks on the Validity of the Developed Model

Throughout Section 6.2.3, extreme condition tests and sensitivity analysis conducted on the developed model are presented. Based on these analyses and direct structure test explained in Section 6.2.1, it is concluded that the model is robust in extreme conditions, and yields valid behavior patterns for various values of the parameters used in the model.

However, since there is no historical data related with the system under consideration, the parameters used in the model, such as aggressive behavior and profit margins of investors are not calibrated. Due to this reason, although sufficient confidence is established on the model structure, the parameters used in the model may require further calibration, as liberalized market data becomes available in the future.

7. SCENARIO ANALYSES

7.1. The Methodology for Scenario Analyses

In the study, projected monthly demand is estimated based on the hourly load curves, obtained from TEIAS. This procedure is explained in detail in Section 5.2.3. In TEIAS's own demand projections, it is assumed that the actual monthly demand deviates from the forecasted monthly demand ranging by -5 per cent to 10 per cent. Based on this observation, the deviation between the projected figures of monthly demand of each time interval and its realized value is assumed to be a random variable with a uniform probability distribution ranging, -5 per cent to 10 per cent of the forecasted monthly demand for that interval. In the simulation runs, in order to allow for seasonal effects on the generation capacities of hydro power plants, random variables defining seasonal precipitation level are also considered. So, the model incorporates stochastic treatment of monthly demand projections, and capacity factors of hydro power plants. Therefore, it is important not to disregard the randomness in the model while comparing simulation outputs of different scenarios. Accordingly, in the present study each scenario is run 10 times, in order to reflect this random nature to the simulation outputs, which are compared with each other. The arithmetic mean of these 10 runs is then used to plot the graphs of 31 indicators, which reflect the behavior of the electricity market. The previously mentioned 31 indicators are listed below;

- The market share of each investor (per cent): This indicator is used to track how competition in electricity market and market power of the investors evolve.
- The SMP (System Marginal Price) ($/MWh): This indicator is used to evaluate the effects of bidding policies, new investment decisions, incentives and regulatory actions on the system marginal price.
- The average monthly pool price ($/MWh): As explained in detail in Section 5.2.3, each day is assumed to consist of nine different time intervals, depending on the hourly electricity demand profiles. Since, the electricity demand of each time interval differs from one another, pool prices of time intervals also differentiate from each

other and pool price of each time interval is determined during the planning horizon. For ease of analysis, weighted average of these nine time intervals over a month is calculated, named as average monthly pool price and traced throughout the scenario analysis. The average monthly pool price is also used to evaluate the effect of investor behavior and decision, incentives and regulatory actions on pool prices.

- The electricity reserve margin (per cent): This indicator is used to understand how investor behavior and different financial and regulatory tools influence available supply in excess of peak demand.
- The remaining primary energy resources' reserves (MW): This performance measure is used to trace the potential total capacity of each plant type that can be build, by considering the remaining available primary energy resources' reserves.
- The cumulative revenue and net profit of each investor ($): These performance measures are used to examine how the investment decisions of the inverstors, financial and regulatory policies affect the revenue and net profit of the investors on the long run.
- The annual peak demand (MW): In case demand is price elastic, this performance measure is used to evaluate the impact of different policies on the demand side of the electricity market.
- Total installed capacity and total installed capacity of each power plant type (MW): These performance measures are used to understand the effect of different policies on the power plant portfolio in the market.

The model has a flexible structure for parametric studies, such that parameters affecting the market can be changed and the results of selected strategies/policies (set of parameters) can be analyzed. Total number of possible scenarios (TNPS) that can be individualy run and investigated is actually very large (it is around 227.812.500.000.000, calculated via Equation 7.1, through considering combinatorial interactions between parameters and strategies.) Evaluating all these scenarios would require vast amount of computation and analysis time. So, a limited scenario analysis is pursued, in which the effects on the electricity market of the factors displayed in Table 7.1, are studied by a two-phase approach.

$$TNPS = f * t * v * tr * i * r * c * ce * p * a * de * de * e * l * w * s * res * cap * ini * cs \quad (7.1)$$

Abbreviations used in Equation 7.1. are explained below;

- t denotes five different values of the tax exemption ratio (per cent);
- v denotes five different values of the VOLL (\$/MWh);
- tr denotes five different tax rates (per cent);
- i denotes five different values of the interest rate (per cent);
- r denotes five different values of the state support for renewable energy (per cent);
- c denotes five different values of the CO_2 tax (\$/kg);
- ce denotes five different values of the cost of equity (per cent);
- p denotes five different profit margin sets ;
- a denotes totally 3^5 different combinations of aggression level of the investors ;
- de denotes five different debt-equity ratios;
- dg denotes five different annual demand growth rates;
- e denotes five different price elasticities of the electricity demand;
- l is a binary factor denoting the presence of long-term contracts in the market;
- w is a binary factor denoting the presence of withholding in the market;
- s denote is a binary factor denoting the presence of seasonal effect;
- res denotes three different levels of primary energy resources' reserve;
- cap denotes three different levels of the annual capacity addition limit;
- ini denotes 5 different sets of initial power plant portfolios of the investors;
- cs denotes 5 different sets of initial liquid assets of the investors.

Table 7.1 . Factors considered in the scenario analysis

• Presence of withholding	• Tax rate,
• Presence of long-term contracts,	• Debt-equity ratio of the investors,
• Price elasticity of electricity demand,	• Tax exemption policy,
• Presence of CO_2 tax,	• Presence of seasonal effects on capacity factors of wind and hydropower plants,
• Presence of state support for renewable energy,	• VOLL,
• Length of forecast period of the investors.	• Level of aggression of investors.

In the first phase, a preliminary scenario set, including 64 different scenarios, is constructed with the aim of determining the main effect of the above given factors on the electricity market. Factors which affect the market most are determined at the end of the first phase.

In the second phase, a reference scenario set is constructed by the help of information gathered from the first phase. While forming a new scenario set, all other factors/attributes except the one under investigation are kept fixed and the chosen factor is set to different values than the one in the reference scenario set. The results of the analysis are then compared with the reference scenario set and the effects of the factors on the market are determined.

In both of the scenario analysis phases, all players are taken as passive players.

7.2. The Preliminary Scenario Set

In the preliminary scenario analysis, the effects of holding different positions on the critical policy factors listed in Table 7.1 are investigated, while grouping these factors under two categories. The first group consists of producer and producers' power plant portfolio related issues, whereas the second group includes environmental and regulatory issues.

In the first test bed, 32 scenarios are constructed considering the following cases:

- All investors being aggressive or all investors being conservative;
- The Incumbent exercising capacity withholding or not ;
- Long-Term contracts being available or not;
- Seasonal effects on the capacity factor of wind and hydro power plants being considered or not;
- Investors investing on only the six most preferred power plant types, based on the preference list obtained via the AHP study mentioned in Chapter 4, (natural gas, small hydro, large hydro, wind, imported hard coal and lignite) vs. investors investing on all of the eight power plant types considered in the model.

In the second test bed, 32 scenarios are constructed considering the following cases:

- The long-term demand elasticity being active or not (since short-term demand elasticity of electricity is nearly zero, it is not considered in the model);
- The annual capacity addition limits being enforced or not;
- The VOLL being 2000 $/MWh versus 3000 $/MWh;
- The CO_2 tax being enforced or not;
- State support for renewable investment being available or not.

As described in Section 5.2, there are five different producers (investors) in the model with three optional behavior types (aggressive, neutral, passive), which means 243 (3^5) different cases. Considering the four remaining parameters included in the first test bed, together with these 243 combinations will result in 2916 different scenarios. As it would require a large amount of time to analyze all these scenarios, instead of considering all combinations of the investors' aggressiveness level, it is assumed that all five investors are either aggressive (all together) or conservative (all together). Similarly, the other policy factors, such as power plant types or withholding levels, would easily be expanded to cover more than two states. However, such an approach would exponentially increase the number of scenarios to be investigated. Accordingly, each factor is regarded to be in one of two possible states and the resulting test bed thus includes only 32 scenarios.

In a similar fashion, in the second test bed only two alternative values are considered for each of the five parameters, which leads to 32 additional scenarios. Two test bed ends up with 64 different scenarios. As discussed before, these 64 scenarios are run for the planning horizon of 20 years and the 31 indicators describing the market are tracked for each scenario. The associated graphs (displaying the value of each indicator over the planning horizon) obtained via the preliminary analysis and the secondary scenario analysis are given in Appendix A and Appendix B presented in the CD-ROM. These graphs display the behavior of the electricity market in different settings for a period of 240 months (plus 40 months to see the after effects).

The following assumptions are made for each scenario in the primary scenario set:

- The investors' forecast period for estimating future supply-demand gap and price in the market is 5 years.

- The country's capacity of natural gas, diesel-oil and imported hard-coal, which are the import dependent non-renewable primary energy resources considered in the model, is assumed to be 4 times the actual present value, (considering mutual agreements between Turkey and the supplier countries).
- The capacity of domestic primary energy resources (small-hydro, large-hydro, geothermal, lignite) is assumed to be 1.5 times the actual present value, in regard to potential new findings and physical limitations.
- In case the producers are aggressive, their profit margins are as follows:
  - New Entrant:35 per cent
  - IPP: 28 per cent
  - IPP2: 29 per cent
  - IPP3: 32 per cent
  - Incumbent: 23 per cent
- In case the producers are conservative, their profit margins are as follows:
  - New Entrant:45 per cent
  - IPP: 37 per cent
  - IPP2: 40 per cent
  - IPP3: 43 per cent
  - Incumbent: 31 per cent

The composition of the plant portfolios of all investors is given in Table 7.2. and Table 7.3.

Table 7.2. Power plant portfolio of the investors (MW) at the beginning of planning horizon

	Incumbent	IPP	IPP2	IPP3
Hard Coal	300	180	0	0
Small- Hydro	0	21	0	0
NG	2800	1875	1445	1200
Large-Hydro	9600	600	204	0
Lignite	4149	0	0	2084
Diesel-Oil	890	660	0	0
Wind	0	0	7.2	0
Geothermal	15	0	0	0

Table 7.3. Power Plants under construction (MW)
at the beginning of planning horizon

	Incumbent	IPP	IPP2	IPP3
Hard Coal	1764	0	0	0
Hydro Small	0	0	0	50
NG	500	250	0	500
Hydro	500	0	727	0
Lignite	0	1082	0	0
Diesel Oil	0	0	0	100
Wind	0	0	0	0
Geothermal	0	0	0	0

7.2.1. Results of the Preliminary Scenario Analysis

As mentioned, each of the scenarios described in Section 7.1 is run 10 times (using different seeding) and arithmetic averages of the 31 indicators described in Section 7.1 over these 10 runs are recorded over the 240 (plus 40) month planning horizon. The comparison of the results led to the following findings;

1. The increasing demand is preferred to be met by power plant types having lower (in comparison to the other power plant types) variable (unit production cost) and investment costs (such as natural gas power plants and small-hydro power plants). As the available resource reserves of these plant types are used up in time, other, more expensive investment options are undertaken and the pool price displays sharper increases in the face of rapidly increasing demand.
2. In the 64 scenarios considered, no wind power plant is undertaken (probably because of their high variable and investment costs). Even in the scenarios with 20 per cent state support for renewable energy, investing in wind power plants does not become desirable.
3. If there is no capacity addition limit on hydro- power plants, regardless of the other scenario settings, power companies prefer to invest in small hydropower plants before the 60^{th} month.

4. The major effect of state support for renewable plants is changes in the market plant portfolio composition in favor of large hydropower and geothermal plants and consequently a decrease in the system marginal price. As the construction time for hydropower plants is comparatively longer than other plant types (5.5 years on average), when investors prefer to invest in such power plants, the growth rate for installed capacity remains lower than the demand growth rate, which in turn causes prices to increase and demand (if price elasticity is non-zero) to decrease. Besides, state support for renewable plants acts as an inducement for competitors to enter the market with new power plant investments, which in turn reduces the market share of the Incumbent.
5. As the major part of the existing power plant pool is composed of thermal power plants, imposing CO_2 tax causes the pool price to increase.
6. In the presence of price elasticity of electricity demand,, due to the CO_2 tax (and the resulting price increase) demand/demand growth rate and new investment amount decrease.
7. In the presence of price elasticity of electricity demand,, imposing the CO_2 tax causes a shift in new investments from thermal plants to renewable plants, within the limits of the relevant reserves.
8. Withholding raises the market price and causes competitors to enter the market with new power plants. In the presence of withholding, due to higher prices in the market, capital intensive type plants, namely large hydro, lignite and imported hard-coal plants, became attractive to investors. As a consequence, total installed capacity of these plant types is much higher when there is withholding. Therefore, due to increasing installed capacity and excess capacity (i.e. reserve margin), the Incumbent's market share and pool price decrease in the long-term. Besides, in case of demand elasticity, the presence of withholding (and the resulting price increase) triggers a decrease in the demand/demand growth rate, which in turn causes an excessive installed capacity, a decrease in the market price and a rebounce in the demand/demand growth rate. To sum up, the overall effect of withholding is an oscillation in the overall electricity demand.
9. If seasonality is considered in the model, monthly capacity factors of wind and hydro plants are not constant but vary seasonally. As a consequence, in scenarios where seasonality is considered, wind and hydro plants produce more in winter and autumn than in the rest of the year (due to higher wind and rain in these seasons). The demand

in the market, on the other hand, is higher in winter (especially in December and January). As the demand of electricity in the market and capacity factors of wind and hydropower plants exhibit similar seasonal variations, it is concluded that seasonality should be definitely included in the analyses, to capture seasonal oscillation in pool prices and excess capacity (accordingly, in the second scenario analysis phase, seasonality effects are considered in all of the scenarios).

10. Since aggressive investors' rate of return (ROR) expectation from new investments is lower in comparison to conservative investors, aggressive investors are more apt to make new investments. As a result, in the scenarios with aggressive investors, total installed capacity and consequently reserve margin are higher in comparison to the scenarios with conservative investors. Besides, aggressive investors' profit margin is lower than conservative investors' profit margin. So, when the investors are aggressive, the average pool price is lower due to higher reserve margin and lower profit margins of the investors.
11. In scenarios with annual capacity addition limits on hydro plants, investors make more investments in natural gas plants, which have shorter construction times. As a result, during the intermediate years, the supply gap in these scenarios is less than that of the case without annual capacity addition limit on hydro plants. Besides, during the preliminary scenario analysis, it is observed that presence of annual capacity addition limit in the market over shadows the effects of other factors, (especially the state support for renewable energy) on the market.

Based on the first phase of the scenario analysis, the following factors are found to have the most significant impacts on the electricity market:

- The aggression level of investors;
- The price elasticity of demand;
- Presence of withholding in the market;
- Presence of incentives for renewable energy plants;
- Presence of annual capacity addition limit on hydro plants in the market;
- Presence of the seasonal effects on the capacity factors of the wind and large-hydro power plants.

7.3. The Second Scenario Analysis

In the second phase of the scenario analysis, the effects of the following five factors on the electricity market are evaluated:

1. Presence of tax exemptions;
2. Presence of incentives for renewable energy plants;
3. Presence of long-term contracts in the market;
4. Different forecast periods used in estimating the near future demand-supply gap and pool price;
5. Deploying different debt-equity ratios (i.e. giving consideration to different investor capital structures in new investments).

First, a reference scenario set is constructed by the help of information gathered from the preliminary scenario analysis explained in Section 7.2.1. In order to determine the individual effects on the market of the five factors cited above, all other factors/attributes except the one under investigation are kept fixed and the chosen factor is set to different values from the values in the reference scenario set, and in this way a new scenario set different from the reference scenario set is formed. This methodology ends up with a new test bed and the model is run for each scenario in this test bed. The simulation outputs of each scenario set are then compared with the reference scenario set, (presented in the next section) for the 31 indicators, which describe the behavior of the electricity market.

7.3.1. Description of the Reference Scenario Set and the Test Bed used in the Second Phase of Scenario Analysis

The reference scenario set includes different settings of the factors having the most significant effects on the electricity market, as determined in the preliminary scenario analysis. As already explained in Section 7.2., these factors are, aggressiveness of investors, price elasticity of demand, presence of withholding, presence of incentives for renewable energy plants support, and presence of annual capacity addition limit in the market. Two of these factors are not included in the reference scenario set:

- Presence of annual capacity addition limit in the market is deliberately not included in the reference scenario set, as it overshadows the effects of other factors on the market.

- Presence of incentives for renewable energy plants support is not included in the reference set, but it is included in the test bed, in order to analyze its effects on the electricity market more comprehensively.

Accordingly, various settings of the key factors defining the eight scenarios in the reference scenario set are given in Table 7.4.

Table 7.4. Scenarios considered in the reference scenario set

Scenario	**Withholding in the Market (Exists or Not)**	**Price Elasticity of Demand**	**Aggression of Investors**
1	No	0	Aggressive
2	Yes	0	Aggressive
3	No	- 0,5	Aggressive
4	Yes	- 0,5	Aggressive
5	No	0	Conservative
6	Yes	0	Conservative
7	No	- 0,5	Conservative
8	Yes	- 0,5	Conservative

Additionally the following assumptions are made for each scenario in the Reference Scenario Set;

- The tax rate is 20 per cent;
- The tax exemption ratio is 40 per cent;
- There is no CO_2 tax;
- There is no incentive for renewable energy plants;
- There are no long term contracts;
- The debt/equity ratio for all new investment projects is three;
- Investors' span of foresight (forecast period) is two years;
- Seasonal effects (on capacity factors of wind and hydro plants, and also the annual precipitation rate) are considered
- In case of investors being all aggressive, their profit margins are set as follows:

    - New Entrant: 35 per cent
    - IPP: 20 per cent
    - IPP2: 21 per cent
    - IPP3: 23 per cent
    - Incumbent: 17 per cent
- In case of investors being all conservative, their profit margins are as follows:
    - New Entrant: 40 per cent
    - IPP: 31 per cent
    - IPP2: 31 per cent
    - IPP3: 33 per cent
    - Incumbent: 27 per cent

Reference scenario set is the 1st scenario set in the Appendix B. The details of the scenarios that are included in the test bed are given below:

1. The scenario set for investigating the effects of State Renewable Support on the electricity market: All parameters are the same as in the reference scenario set, but the rate of state renewable support, which is assumed have two values, namely 15 per cent and 35 per cent. There are 16 scenarios (eight with 15 per cent state renewable support and eight with 35per cent) in this set. (2nd and 3rd scenario sets in the Appendix B)
2. The scenario set for investigating the effects of debt-equity ratio of the investors on the electricity market: All parameters are the same as in the reference scenario set, but the debt/equity ratio, which is assumed have two values, (namely 40 per cent and 60 per cent.) There are 16 scenarios in this set. (4th and 5th scenario sets in the Appendix B)
3. The scenario set for investigating the effects of the Forecast Period on the electricity market: All parameters are the same as in the reference scenario set, except the forecast period, which is assumed to be five years, as opposed two years. There are eight scenarios in this set. (6th scenario set in the Appendix B)
4. The scenario set for investigating the effects of Long-term Contracts on the electricity market: All parameters are the same as in the reference scenario set, except the availability of long-term contracts. There are eight scenarios in this set. (7th scenario set in the Appendix B)
5. The scenario set for investigating the effects of Tax Exemption Rate on the electricity

market: All parameters are the same as in the reference scenario set, but the tax exemption rate, which is assumed to be zero per cent, as opposed to 40 per cent. There are eight scenarios in this set. (8^{th} scenario set in the Appendix B)

To sum up, in the second phase of scenario analysis, 64 different scenarios (56 in test beds, eight in the reference scenario set) are compared with each other. The associated graphs (displaying the value of each indicator over the planning horizon), obtained via the second scenario analysis, are given in Appendix B presented in the CD-ROM.

7.3.2. Results of the Second Scenario Analysis

As explained before, there are eight scenarios in each scenario set. The differences within these scenario sets can be seen in the graphs presented in Appendix B.

Results of the second scenario analysis are discussed in Tables 7.5-7.11. In each table, different scenario sets are compared with the reference scenario set. Similar properties of both scenario sets are explained in merged cells. If different behaviors are observed in compared scenario sets, these are explained in separate columns.

The effects of different parameters (state renewable support, debt ratio, forecast period, long-term contract, tax exemption rate) on the electricity market are discussed through Table 7.5-Table 7.11.

It is particularly important to note here once again that system dynamics approach is used and the main objective of the present study is not to make a point by point prediction of any variable. The aim of comparing the reference scenario set with the ones in the test bed is principally to understand the effects of different factors on the behavior of the electricity market. In other words, since point by point prediction is out of scope of the systems dynamic approach followed in this thesis, seldomly quantitative figures are cited in the tables, which present the comparisons of the scenario sets in the test bed and in the reference scenario set. However, the magnitude of the differences between the scenario sets, explained through Tables 7.5-7.11, are described by the words; slightly, much, significantly and distinctly (in ascending order).

Table 7.5. The effect of the State support for renewable energy on the electricity market in price inelastic demand case

	State Support for Renewable Energy is 0 % (Reference Scenario Set)	**State Support for Renewable Energy is 15 % (2nd Scenario Set)**	**State Support for Renewable Energy is 35 % (3rd Scenario Set)**
Total Installed Capacity	The investors can not easily afford investing in large hydro plants in case of no state support for renewable energy. • As a consequence, at the end of the planning horizon, total installed capacity in the reference scenario set is much lower than that of the case in the 2nd scenario set and significantly lower than that of the case in the 3rd scenario set. • As more large hydro plants are constructed in the 2nd and 3rd scenario sets, and these plants are introduced to the market after their long construction times,until the 181st month, total installed capacity in the reference scenario set is slightly higher and much higher than total installed capacity in the 2nd and 3rd scenario sets, respectively.	• Owing to state support for renewable energy, total installed capacity in the 2nd scenario set is much higher than that of the case in the reference scenario set at the end of the planning horizon. • In comparison to the reference scenario set, total installed capacity in the 2nd scenario set is slightly lower until the 181st month, because the ratio of large-hydro plant capacity being constructed to the total capacity being constructed is higher. (As construction time of large-hydro plant is 60 months on average, they are introduced to the market after the 181st month.)	• As a result of the reasons mentioned in the neighboring box; • At the end of the planning horizon, total installed capacity in the 3rd scenario set is significantly higher in comparison to the reference scenario set. • In comparison to the reference scenario set, total installed capacity in the 3rd scenario set is much lower until the 181st month.
Peak Demand	Since the annual demand growth rate is the same (seven per cent) in all scenario sets and demand is inelastic, peak demand is the same in all the scenario sets.		
Total Installed Large-Hydro Power Plant Capacity	Due to high investment costs and absence of support for renewable energy, total installed large hydro plant capacity in the reference scenario set is much lower than that of the case in the 2nd scenario set and significantly lower than that of the case in the 3rd scenario set, throughout the entire planning horizon.	As a result of reduced investment costs thanks to support for renewable energy, total installed large hydro plant capacity in the 2nd scenario set is much higher than that of the case in the reference scenario set, throughout the entire planning horizon.	Because of the reason explained in the neighboring box; total installed large hydro plant capacity in the 3rd scenario set is significantly higher than that of the case in the reference scenario set, throughout the entire planning horizon.

Table 7.5. The effect of the State support for renewable energy on the electricity market in price inelastic demand case (cont.)

<table>
<tr><td rowspan="2">Total Installed Small-Hydro Power Plant Capacity</td><td colspan="3">Because of their lower variable and investment costs, as compared to the other plant types considered, small hydro plants are constructed up to the full national potential during the first half of the planning horizon, regardless of support for renewable energy .</td></tr>
<tr><td>Small-hydro plant capacity constructed until the 125^{th} month utilizes all of the country’s potential.</td><td>• Total installed small-hydro plant capacity in the 2^{nd} scenario set is higher until the 115^{th} month.
• Since all potential is used up, no new small hydro plant investments can be launched after the 115^{th} month.
• As a result, the difference between total installed small hydro plant capacities in the 2^{nd} and reference scenario sets closes down by the 125^{th} month.</td><td>• Total installed small-hydro plant capacity in the 3^{rd} scenario set is distinctly higher until the 109^{th} month.
• The difference between total installed small hydro plant capacities in the 3^{rd} and reference scenario sets closes down by the 125^{th} month.</td></tr>
<tr><td rowspan="2">Total Installed NG Power Plant Capacity</td><td colspan="3">Natural gas plants are preferred over other plant types because of their lowest investment costs. As a consequence, in the scenario sets, all available natural gas potential is utilized until the 240^{th} month.</td></tr>
<tr><td>Since there is no support for renewable energy investors invest more on low cost natural gas plants to meet prospective supply-demand gap in the market. As a consequence until the 229^{th} month, total installed natural gas plant capacity in the reference scenario set is; much higher and distinctly higher in comparison to the 2^{nd} and 3^{rd} scenario sets, respectively.</td><td>Since total installed capacity of large hydro and geothermal plants is higher, owing to the support for renewable energy; total installed natural gas plant capacity in the 2^{nd} scenario set is lower than the case in the reference scenario set (until the 229^{th} month).</td><td>Because of the reason explained in the neighboring box, total installed natural gas plant capacity in the 3^{rd} scenario set is significantly lower than the case in the reference scenario set (until the 229^{th} month).</td></tr>
<tr><td>Pool Price</td><td>• Due to the absence of support for renewable energy, large hydro and geothermal plants’ share in the total installed capacity is lower, while hydro and geothermal plants have the lowest variable costs among all plant types.
• As a result, average monthly pool price in the reference scenario set, is much higher in comparison to the cases in the 2^{nd} and 3^{rd} scenario sets.</td><td colspan="2">• Owing to the support for renewable energy, large hydro and geothermal plants’ share in total installed capacity is higher in comparison to the reference scenario set.
• As a consequence, the average monthly pool price in the 2^{nd} and 3^{rd} scenario sets is much lower than that of the case in the reference scenario set.
• The difference between the pool prices in the reference scenario set and 2^{nd} and 3^{rd} scenario sets becomes larger in the second half of the planning horizon, as large hydro and geothermal plants more become active during this period.</td></tr>
</table>

Table 7.5. The effect of the State support for renewable energy on the electricity market in price inelastic demand case (cont.)

<table>
<tr>
<td>The Effect of Withholding on the Market</td>
<td colspan="3">• In case of withholding, there are price spikes in the market and average pool prices are significantly higher, regardless of support for renewables.

• Since the presence of withholding results in high pool prices, investors make much more new investments than they do in a market without withholding, regardless of support for renewable energy. (i.e. in the presence of withholding in the market, the prompting effect of renewable support on new investments is less than the case in the market with no withholding.)</td>
</tr>
<tr>
<td rowspan="2">Total Installed Geothermal Power Plant Capacity</td>
<td colspan="3">No geothermal plant is introduced to the market up to the 90^{th} month.</td>
</tr>
<tr>
<td>Since there is no support for renewable energy, total installed geothermal plant capacity is significantly lower and distinctly lower in comparison to the 2^{nd} and 3^{rd} scenario sets, respectively.</td>
<td>Owing to the support for renewable energy, total installed geothermal plant capacity in the 2^{nd} scenario set is significantly higher than that of the case in the reference scenario set.</td>
<td>Similarly, total installed geothermal plant capacity in the 3^{rd} scenario set is distinctly higher than that of the case in the reference scenario set.</td>
</tr>
<tr>
<td>Total Installed Capacity of Wind Power Plants</td>
<td colspan="3">As investment and variable costs of wind plants are high, no wind plants are installed throughout the planning horizon, (i.e. the level of pool price and even the existence of 35 per cent-support for renewable energy is not sufficient to foster investments in wind plants.)</td>
</tr>
<tr>
<td>Lignite Power Plants</td>
<td>Total lignite plants constructed throughout the planning horizon is;
• much higher in comparison to the 2^{nd} scenario set.
• significantly higher in comparison to the 3^{rd} scenario set.</td>
<td>Since total large-hydro and geothermal plant capacity constructed in the 2^{nd} scenario set is higher, total lignite plant capacity constructed is less than that of the case in the reference scenario set.</td>
<td>As explained in the neighboring box, total lignite plant capacity constructed throughout the planning horizon is significantly lower, in comparison to the case in the reference scenario set.</td>
</tr>
<tr>
<td>Market Share of the NE</td>
<td>Because of the reasons explained in the neighboring box, the average market share of the NE, throughout the planning horizon, in the reference scenario set is higher than that of the case in the counter scenario sets.</td>
<td colspan="2">An increase in renewable support or in any other incentive renders new investments to be attractive to all investors, either existing or new entrant.
• Since support for renewable energy motivates the NE to invest in hydro plants, the share of the hydro plants in NE's investment portfolio is higher than that of the case in the reference scenario set. On the other hand, hydro plants have long lead times, so NE's market share increases slower than the case in the reference scenario.
• As a result, the NE's average market share throughout the planning horizon is lower than the case in the reference scenario set.</td>
</tr>
<tr>
<td>Cumulative Profit of Investors (Excluding NE)</td>
<td>• Since there is no support for renewable energy, share of the renewable energy alternatives in the total installed capacity is</td>
<td colspan="2">Because of the reasons explained in the neighboring box; Investors' cumulative profit at the end of the planning horizon is higher than that of the case in the reference scenario set.</td>
</tr>
</table>

Table 7.5. The effect of the State support for renewable energy on the electricity market in price inelastic demand case (cont.)

	smaller in comparison to the 2nd and 3rd scenario sets. • Consequently, thermal plants have a larger share in the overall portfolio in comparison to the 2nd and 3rd scenario sets. • On the other hand, thermal plants have higher production costs, so investors' cumulative profit at the end of the planning horizon is lower than the cases in the 2nd and 3rd scenario sets.	
Cumulative Profit of NE	• Since, there is no support for renewable energy, the NE invests less in large-hydro plants and more in thermal plants, so he enters to the market earlier than that of the cases in the 2nd and 3rd scenario sets (due to short lead times of thermal plants). • As a consequence, the NE's cumulative profit at the end of the planning horizon is higher than that of the cases in the 2nd and 3rd scenario sets.	As explained in the neighboring box, NE's cumulative profit at the end of the planning horizon is lower than that of the case in the reference scenario set.

Table 7.6. The effect of debt ratio on the electricity market in the inelastic demand case

<table>
<tr><th></th><th>Debt Ratio 75 %
(Reference Scenario Set)</th><th>Debt Ratio 60 %
(5th Scenario Set)</th><th>Debt Ratio 40 %
(4th Scenario Set)</th></tr>
<tr><td>Total Installed Capacity</td><td>• As a consequence of investors' lower ROR expectation from new investments and higher debt amounts, total installed capacity in the reference scenario set is much higher than that of the 4th and 5th scenario sets, at the end of the planning horizon.
• Total installed capacity in the reference scenario set is much lower than that the 4th and 5th scenario set until the end of the 3rd quarter of the planning horizon. Due to the following reasons;
o There are more large hydro plant investments in the market. However, most of these investment decisions are taken after the 100th month, and due to their long construction times, most of these power plants are introduced to the market after the 180th month.
o Total installed imported hard-coal and lignite plant capacity is much higher in comparison to the counter scenario sets. On the other hand, most of these power plants also became active during the last quarter of the planning horizon.</td><td colspan="2">As the investors' debt-equity ratio decrease they make less investments especially on highly capital intensive plant types (such as large hydro and coal plant). Because;
• The investors, especially the NE and the IPPs' may not have enough equity to invest on highly capital intensive plant types so they have to borrow money.
• Besides, the investors' ROR expectation from new investments increases as their debt-equity ratio decreases. (This is the main reason why investors mostly invest on natural gas plants, which have low investment costs.)
• Because of the reasons cited above, total installed capacity at the end of 20 years is considerably less, in comparison to the reference scenario set.
• Total installed capacity in the 4th and 5th scenario sets is higher than that of the reference scenario set, until the 180th month. Since,
o Investors invest more on natural gas plants than they do in the reference scenario set.
o Construction time of natural gas plant is shorter than that of coal and hydro power plants.
o As a result, total installed capacity increases faster and earlier, than it does in the reference scenario set.</td></tr>
<tr><td>Peak Demand</td><td colspan="3">Since the annual demand growth rate is the same (7per cent) in all scenario sets and demand is inelastic, peak demand is the same in scenario sets considered.</td></tr>
<tr><td>Excess Capacity Ratio</td><td>Since more large-hydro plants are constructed during the planning horizon, and these plants have the longest construction times, the total installed capacity lags behind that of the 4th and 5th scenario sets, until large-hydro plants are activated.
Due to this reason, upto the 130th month, excess capacity ratio, is much lower, in comparison to the 5th and 4th scenario sets.</td><td colspan="2">In the 4th and 5th scenario sets, the major part of the investments are on natural gas plants, which have short construction times.
Accordingly, at intermediate years, total installed capacity in the 4th and 5th scenario sets is higher than that of the the reference scenario set. So, at intermediate years, excess capacity ratio is higher than that of the reference scenario set.</td></tr>
<tr><td>Total Installed Small-Hydro Power Plant Capacity</td><td colspan="3">Because of their lowest variable cost and second lowest investment cost, small-hydro power plants are widely constructed until the 125th month of the planning horizon, (that is until all the available national potential is utilized).
Therefore, during the second half of the planning horizon, total installed capacity of small-hydro power plants is the same in all scenario sets considered.</td></tr>
</table>

Table 7.6. The effect of debt ratio on the electricity market in the inelastic demand case (cont.)

<table>
<tr>
<td rowspan="1">Total Installed Large-Hydro Power Plant Capacity</td>
<td>• If the investors are conservative it is;
o distinctly more than it is in the 4^{th} scenario set,
o significantly more than it is in the 5^{th} scenario set.

• If the investors are aggressive, it is;
o much more than it is in the counter scenario sets.</td>
<td>• If the investors are conservative, it is, significantly less than it is in the reference scenario set.
• If the investors are aggressive, it is much lower than the reference scenario set.</td>
<td>• If the investors are conservative, it is,
o distinctly less than it is in the reference scenario set.

• If the investors are aggressive, it is;
o much lower than the reference scenario set.</td>
</tr>
<tr>
<td rowspan="2">Total Installed Natural Gas Power Plant Capacity</td>
<td colspan="3">Natural gas plants are preferred over other plant types because of their lowest investment cost. As a consequence, in all scenario sets, all available natural gas potential is utilized until the 240^{th} month of the planning horizon.</td>
</tr>
<tr>
<td>• As there are more large-hydropower, lignite, geothermal, and imported-hard coal plants for meeting the projected demand, fewer natural gas power plants are constructed until the 217^{th} month.
• The difference between the scenario sets with 40 per cent and 60 per cent debt ratios and the reference scenario set closes down between 217^{th} and 240^{th} months.</td>
<td colspan="2">• As there are fewer large-hydro, lignite, geothermal, and imported-hard coal plants in the market, until the 217^{th} month, initially and up to the third quarter, more natural gas plants are installed, as compared to the reference scenario set.
• As the country's natural gas potential for natural gas plants is almost exhausted by the 217^{th} month, no such plants are constructed after this time. Therefore, the gap between 5^{th} and 4^{th} and the reference scenario set closes down between 217^{th} and 240^{th} months.</td>
</tr>
<tr>
<td>The Effect of Withholding on Average Monthly Pool Price</td>
<td colspan="3">In case there is withholding in the market, the average monthly pool price is distinctly higher in all three scenario sets, in comparison to the scenarios withhout withholding.</td>
</tr>
<tr>
<td rowspan="2">Total Installed Geothermal Power Plant Capacity</td>
<td colspan="3">(Note that the capacity of geothermal power plants, which are already on service and under construction at the beginning of planning horizon is the same in all three scenario sets.)
The forecast period used in estimating demand-supply gap is 2 years in these scenario sets. As the country's capacity of natural gas and of small hydro power plants suffices up to 97^{th} month to meet the forecasted supply gap , no geothermal plants are introduced to the market until this month.</td>
</tr>
<tr>
<td>• As a consequence of investors' lower ROR expectation from new investments, shares of more capital intensive plant types (than natural gas and small-hydro plants) in the new investments is higher.
• Therefore, compared to the counter scenario sets, total installed geothermal plant capacity is much higher after the 97^{th} month.</td>
<td colspan="2">• Since the debt-equity ratio is lower and consequently expected ROR is higher, total installed capacity of more capital intensive plant types are lower.

• Therefore, total installed geothermal plant capacity is much lower after the 97^{th} month.</td>
</tr>
</table>

Table 7.6. The effect of debt ratio on the electricity market in the inelastic demand case (cont.)

Total Installed Capacity of Wind Power Plants	Except in the scenario with aggressive investors and no withholding in the reference scenario set, no new wind power plant are introduced to the market during the entire planning horizon. In the mentioned scenario, total wind plant capacity introduced to the market is around one per cent of the national stock.	No new wind plant is introduced to the market during the full planning horizon, since it does not meet the ROR expectations of investors.
Total Installed Imported Hard-Coal Power Plant Capacity	Since higher debt ratio results in lower ROR expectations, comparatively high capital intensive plants are constructed more in comparison to the 5th and 4th scenario sets. Therefore, otal installed imported hard-coal plant capacity, at the end of the planning horizon, is higher than that of the counter scenario sets.	Since lower debt ratios result in higher ROR expectations, total installed imported hard coal plant capacity in the market is much lower.
Total Installed Lignite Power Plant Capacity	Eagerness to invest in more capital intensive plant types increases as the debt ratio increases. As a consequence, total installed lignite plants are much higher both during and at the end of the 20 year planning horizon.	As explained in the neighboring box, total installed lignite power plants are much less both during and at the end of the 20 year planning horizon.
Total Installed Diesel-Oil Power Plant Capacity	Because of the high cost of the required primary energy resource, less than 1000 MW of diesel oil plants are introduced to the market during the planning horizon.	
Average Pool Prices	As there are more large-hydro and geothermal plants in the market, the average pool prices observed during the planning horizon is slightly lower.	As explained in the neighboring box, the average pool prices observed during the planning horizon, is slightly higher as compared to that of the case in the reference scenario set.
Cumulative Profit of Investors	The investors pay less tax for their EBIT(earnings before interest and tax), as their debt ratio increases. So their net profits increase. Therefore,(at the end of 20 years), investors' cumulative profit in the reference scenario set is distinctly higher than it is in the counter scenario sets.	Investors' net profit during the planning horizon and at the end of 20 years is distintcly lower during the planning horizon.

Table 7.7. The effect of different forecast periods on the electricity market in the inelastic demand case

	Forecast Period: 5 Years (6th Scenario Set)	**Forecast Period: 2 Years (Reference Scenario Set)**
Peak Demand	Since the annual demand growth rate is the same (7 per cent) in both of the scenario sets and demand is inelastic, peak demand is the same in both cases.	
Total Installed Capacity	• As the investors' investment decisions are based on a projection of the demand and plant retirement trends of the next five years, they invest more and the amount of total installed capacity in the market is distinctly higher, especially between the 33rd and 181st months. • The difference in total installed capacity between two scenario sets partially closes down between the 181st -240th months. Since, pool prices in the 6th scenario set are distinctly lower in comparison to the reference scenario set, the market is much less attractive for the investors in the 6th scenario set, than it is in the reference scenario set. • As a consequence, total installed capacity is much higher in the 6th scenario set than it is in the reference scenario set (since the gap between two scenario sets are distinctly large until the 181st month, it is not completely closed until the 240th month).	• As the foresight span of each investor is 2 years; they behave in a more myopic way in comparison to the scenario set with 5 year forecast period. In other words, the investors are apt to respond to more immediate signals. As a result, the amount of total installed capacity in the market is distinctly lower between the 33rd and 181st months. • Since reserve margin in the reference scenario set is distinctly higher than that of the 6th scenario set, pool prices in the reference scenario set are distinctly higher than pool prices in the 6th scenario set. As a consequence, new investments are more attractive in the reference scenario set, as compared to the counter scenario set. As a result, the difference in total installed capacity between two scenario sets partially closes between the 181st – 240th months. • As a consequence, the total installed capacity in the reference scenario set is much lower than the total installed capacity in the 6th scenario set, at the end of the 240th month.

Table 7.7. The effect of different forecast periods on the electricity market in the inelastic demand case (cont.)

<table>
<tr><td>Excess Capacity Ratio</td><td>• Excess capacity ratio in the 6th scenario is distinctly higher than it is in the counter scenario set, between 33rd and 181st months, because of the distinctly higher total installed capacity.
• The difference in total installed capacity between the scenario sets partially closes between 181st and 240th months.
• Consequently, excess capacity ratio is much higher than in the reference scenario set, by the 240th month.</td><td>• Excess capacity ratio is distinctly lower than in the counter scenario set, between 33rd and 181st months, because of significantly lower total installed capacity.
• The difference in total installed capacity between the scenario sets partially closes between the 181st and 240th months.
• Consequently, excess capacity ratio is much lower than in the counter scenario set by the 240th month.</td></tr>
<tr><td>Average SMP</td><td>• As significantly more small-hydro power plant capacity (having lower unit production cost) is installed until the 61st month, the average SMP decreases suddenly at that time.
• In order to meet the rapidly increasing demand, the investors start to invest on power plant types with higher unit production costs (wind, diesel oil, imported hard coal) at earlier stages of the planning horizon.
• As a consequence, the average SMP starts to increase earlier. Because, although excess capacity ratio in the 6th scenario set is much higher than it is in the reference scenario, still the supply gap exists in the 6th scenario set during peak hours. So, during these periods the most expensive units (in terms of marginal costs) are also utilized.</td><td>• As significantly less small-hydro plant capacity is installed until 61st month, the average SMP decreases gradually.
• the investors start to invest on power plant types with higher unit production costs (wind, diesel oil, imported hard coal), at comparatively later stages of the planning horizon than in the counter scenario set. As a consequence, the average SMP starts to increase later.</td></tr>
<tr><td>Average Monthly Pool Price</td><td colspan="2">In both scenario sets, the average monthly pool price increases at the beginning of the planning horizon. As new hydro plants, which have the lowest unit production costs and new geothermal plants (few) are introduced to the market, the average SMP decreases, which in turn causes the monthly pool price to decrease.
By the 240th month, the average monthly pool price assumes an increasing trend, as a result of the increasing SMP, due to the factors above explained.</td></tr>
</table>

Table 7.7. The effect of different forecast periods on the electricity market in the inelastic demand case (cont.)

<table>
<tr>
<td></td>
<td>• In comparison to the initial average monthly pool price, the overall average of monthly pool prices observed during 20 years is;

o slightly higher, if there is withholding;
o much lower, if there is no withholding.

• As the excess capacity ratio and total installed capacity in the 6th scenario set is distinctly higher than it is in the reference scenario set after the 33rd month, and more small-hydro, geothermal and large-hydro plants (plants with low variable costs) are installed at earlier stages of the planning horizon, average electricity prices of the entire 20 years, and average monthly pool prices observed during the planning horizon are distinctly lower.</td>
<td>• In comparison to the initial average monthly pool price, the overall average of monthly pool prices observed during 20 years is much higher.

• As explained in the neighboring box; In the reference scenario set, average electricity prices of the entire 20 years, and average monthly pool prices observed during the planning horizon are distinctly higher, as compared to the 6th scenario set.</td>
</tr>
<tr>
<td>The Effect of Withholding on Average Monthly Pool Price</td>
<td>• In the 6th scenario set, the electricity market is significantly less sensitive to withholding, because of its higher excess capacity ratio (than in the reference scenario set); so, price variations exhibit a smoother nature during the planning horizon. (The effect of withholding on the price seems to be minimal.)

• Height and frequency of the price spikes are distinctly less, in comparison to the reference scenario set.</td>
<td>• The electricity market is distinctly more sensitive to withholding because of lower excess capacity ratio, in comparison to the 6th scenario set.

• There are distinctly more spikes in the average monthly pool price in comparison to the 6th scenario set. Besides, the height of the price spikes observed in the reference scenario set is distinctly higher than the height of the price spikes of the 6th scenario set.</td>
</tr>
<tr>
<td>Effect of Withholding on the Profit of the Investors</td>
<td>Since, the electricity market is distinctly less sensitive to withholding, in the 6th scenario set,

• extra profit earned by the presence of withholding is distinctly lower in comparison to the reference scenario set.
• when there is withholding, investors' monthly profit does not fluctuate as much as in the reference scenario set, because of the factors explained above.</td>
<td>As explained in the neighboring box;

• extra profit earned through withholding is distinctly higher.
• investors' monthly profit highly fluctuates, when there is withholding.</td>
</tr>
</table>

Table 7.7. The effect of different forecast periods on the electricity market in the inelastic demand case (cont.)

<table>
<tr><td rowspan="1">Profit of the Investors</td><td>Cumulative profit of each investor at the end of 20 years is distinctly lower in comparison to the reference scenario set. Since;
• The average electricity price of 20 years is distinctly lower in comparison to the reference scenario set.
• Extra profit earned by the presence of withholding is distinctly lower in comparison to the reference scenario set.</td><td>Because of the reasons explained in the neighboring box, cumulative profit of each investor at the end of 20 years is distinctly higher in comparison to the 6th scenario set.</td></tr>
<tr><td rowspan="2">Total Installed Small-Hydro Power Plant Capacity</td><td colspan="2">Because of their lowest unit production cost and second lowest investment cost small hydro plants are preferred at earlier stages of the planning horizon and are constructed until the end of first half of the planning horizon (that is until all the available national potential is utilized).</td></tr>
<tr><td>• Distinctly more small-hydropower plant capacity is constructed in earlier stages of planning horizon.
• Total installed small hydro plant capacity increases with jumps.</td><td>• Distinctly less small-hydro plant capacity are constructed in later stages of planning horizon.
• Total installed capacity of small hydro plants increases gradually.</td></tr>
<tr><td>Total Installed Large-Hydro Power Plant Capacity</td><td>• Total installed capacity of large hydro plants increase with steep steps.
• Total large hydro plant capacity installed throughout the planning horizon is much higher.</td><td>• Total installed capacity of large hydro plants increase gradually.
• Total large hydropower plant capacity installed throughout the planning horizon is much lower.</td></tr>
<tr><td rowspan="2">Total Installed Natural Gas Power Plant Capacity</td><td colspan="2">Natural gas power plants are the most preferred among all plant types considered, since they have the lowest investment costs. As a consequence, in both scenario sets, all available natural gas potential is utilized until the 240th month.</td></tr>
<tr><td>As the investors' investment decisions are based on a projection of the demand and plant retirement trends of a longer period, they invest more so,
• Total natural gas plant capacity installed by the 205th month is significantly higher.
• Compared to the reference scenario set, distinctly more natural gas plants are installed at earlier stages of the planning horizon.
• As explained in the neighboring box, the difference between the total installed natural gas plant capacity in both scenario sets closes down after the 204th month.</td><td>As explained in the neighboring box,
• Total natural gas power plant capacity installed by the 205th month is significantly lower.
• Compared to the 6th scenario set, distinctly more natural gas plants are installed at later stages of the planning horizon.
• Since pool prices in the reference scenario set are distinctly higher in comparison to the case in the 6th scenario set, the construction of more plants are started after the 181st month. As a result, difference between the total installed natural gas plant capacity in both scenario sets closes down after the 204th month.</td></tr>
</table>

Table 7.7. The effect of different forecast periods on the electricity market in the inelastic demand case (cont.)

<table>
<tr><td>Total Installed Imported Hard Coal Power Plant Capacity</td><td>At the end of the planning horizon, total installed imported hard coal plant capacity is significantly more in comparison to the reference scenario set.</td><td>At the end of the planning horizon, total installed imported hard coal plant capacity is significantly less in comparison to the 6th scenario set.</td></tr>
<tr><td>Total Installed Wind Power Plant Capacity</td><td colspan="2">• Because of their high unit production costs, wind power plants are not perceived by the investors as attractive investments, unless there are high pool prices and/or attractive subsidies in the market.
• If the investors are aggressive;
  o Except in the scenario with no withholding in the reference scenario, during the entire planning horizon, no new wind power plant is introduced to the market in both scenario sets.
• If the investors are conservative,
  o No new wind power plant is introduced to the market in both scenario sets during the entire planning horizon.</td></tr>
<tr><td>Total Installed Lignite Power Plant Capacity</td><td>As the investors’ investment decisions are based on a projection of the demand and plant retirement trends of a longer period, they invest more, so total installed lignite plant capacity during and at the end of the planning horizon is much higher.</td><td>Because of the reason sited in the neighboring box; total installed lignite plant capacity during and at the end of the planning horizon is much lower.</td></tr>
<tr><td rowspan="2">Total Installed Diesel Oil Power Plant Capacity</td><td colspan="2">Because of their highest unit production costs, diesel-oil plants are not widely preferred unless potentials of other primary energy alternatives are used up or the electricity pool price in the market is high enough.
Diesel oil plants are started to be constructed only after the 109th month.</td></tr>
<tr><td>Total capacity of diesel-oil plants is much higher than the amount in the reference scenario set.</td><td>Total capacity of diesel-oil plants is much lower than that amount in the 6th scenario set.</td></tr>
<tr><td>Market Share</td><td>Since higher excess capacity ratio means a more competitive market, monthly fluctuations in the investors’ market share is much higher.</td><td>The fluctuation in the investors’ market share is much lower due to lower excess capacity ratios.</td></tr>
</table>

Table 7.8. The effect of different forecast periods on the electricity market in the elastic demand case

<table>
<tr><th></th><th>Forecast Period: 5 Years
(6^{th} Scenario Set)</th><th>Forecast Period: 2 Years
(Reference Scenario Set)</th></tr>
<tr><td rowspan="2">Peak Demand</td><td colspan="2">• Since, it is assumed that price elasticity of demand activates after the first five year of the liberalization, peak demand exhibits very similar values in both scenario sets in the first five years up to the 73^{rd} month, as the extent of the competitiveness and market deregulation increases.
• Since demand is price elastic in both scenario sets, the telltale seesaw effects of elasticity can be observed in both cases: demand decreases as a reaction to the increase in average monthly pool price, than the price decreases as a reaction to the decrease in the demand and finally the demand increases again as a consequence of the decrease in the price.</td></tr>
<tr><td>As there are distinctly less price spikes and average monthly pool prices are distinctly lower, average peak demand exhibits much higher values, especially after the 133^{rd} month.</td><td>As explained in the neighbouring box; average peak demand exhibits much lower values especially after the 133^{rd} month.</td></tr>
<tr><td>Total Installed Capacity</td><td>• As the investors' investment decision is based on a projection of the demand and power plant retirement/expansion trends for the next five years,
• As peak demand is much higher in comparison to the reference scenario set;
Total installed capacity in the market is significantly higher after the first 33 months.</td><td>• As the foresight span of each investor is 2 years, the investors are more myopic in comparison to the investors in the 6^{th} scenario set. In other words, the investors are apt to respond to more immediate signals.
• As the peak demand is much lower,
Total installed capacity in the market is significantly lower after the first 33 months.</td></tr>
<tr><td rowspan="2">Excess Capacity Ratio</td><td colspan="2">Excess capacity ratio is the same in both scenario sets until the 33^{rd} month, as the peak demand and total installed capacity is the same.</td></tr>
<tr><td>Although total installed capacity in the 6^{th} scenario set is significantly higher, excess capacity ratio in the 6^{th} scenario set is sometimes much lower than it is in the reference scenario set. (due to higher demand)</td><td>As explained in the neighboring box, excess capacity ratio in the reference scenario set is sometimes much higher than it is in the 6^{th} scenario set.</td></tr>
<tr><td>Average SMP</td><td colspan="2">• As small hydro plants, having lower unit production cost, are constructed at earlier stages of the planning horizon, average SMP decreases at around 61^{st} month.
• Average demand is higher in scenarios in case of elastic demand, compared to the cases with inelastic demand. As a consequence, in scenarios with elastic demand, more supply is required to meet comparatively higher demand in the market. In these scenarios, as the plant types with lower unit production cost are preferred at earlier stages of the planning horizon, the country's primary enery resources' poteantial of these plant types are exhausted earlier. As a consequence, more investment is done on plant types with high unit production costs at earlier stages of the planning horizon, in comparison to the scenarios with inelastic demand. The overall consequence is an increase in SMP.
• SMP is much higher in the demand-elastic scenarios as the share of the plant types (with high unit production cost) in the plant portfolio increases faster than it does in the demand-inelastic scenarios.</td></tr>
</table>

Table 7.8. The effect of different forecast periods on the electricity market in the elastic demand case (cont.)

Average SMP	• Total small-hydro plant capacity installed until the 61^{st} month is significantly more. Besides, these plants are introduced to the market suddenly, and unit production cost of these power plant types is lower than that of most other plant types so,the average SMP decreases suddenly at that time. • Then, in order to meet rapidly increasing demand, (due to decreasing electricity prices), investors invest on plant types with high unit production costs (wind, diesel oil, imported hard coal) at earlier stages of the planning horizon. As a consequence, the average SMP starts to increase earlier (since demand is higher and also most expensive units are used to supply demand during the peak hours). • From this point on, the behavior of the SMP in the scenario sets differs from each other depending investors' behavior type. o If the investors are aggressive, low pool prices in the market renders 3 types of power plants (diesel oil, wind and imported hard coal plants) to be unattractive for the investors because of their low ROR and high unit production costs. As a consequence, at around the 240^{th} month, total installed capacity of these plant types is lower in comparison to the reference scenario set. Therefore, average SMP in the 6^{th} scenario set is much lower in comparison to the reference scenario set. o If the investors are conservative; pool prices in the market are much higher than the pool prices in case of presence of aggressive investors. The higher pool price renders the above stated plant types to be more attractive. As a result, plants (diesel oil, wind and imported hard coal plants) are installed more in the 6^{th} scenario set in comparison to the reference scenario set. Therefore, at around the 240^{th} month, the average SMP in the scenarios with conservative investors is much higher than the average SMP in the case of aggressive investors.	• As total small-hydro plant capacity installed until the 61^{st} month is significantly less, and total installed small-hydro plant capacity in the market increases gradually; the average SMP decreases gradually. • Then, the (decrease in/ deceleration of increase in) demand is caused by the increase in the average monthly pool price, which is due to much lower excess capacity ratio (in comparison to the 6^{th} scenario set) until the 133^{rd} month. • As a result, power plant types with high unit production cost (imported hard coal, diesel) are installed at later stages of the planning horizon than in the counter scenario set. Consequently, the average SMP increases at later stages as well. o If the investors are aggressive, at around 240^{th} month, total installed capacity of the plant types, having high unit production cost, is much higher. As a consequence, average SMP in the reference scenario set is much higher than it is in the counter scenario set. o If the investors are conservative, at around 240^{th} month, total installed capacity of the plant types, having high unit production cost, is much lower. As a consequence, average SMP in the reference scenario set is much lower than it is in the counter scenario set.

Table 7.8. The effect of different forecast periods on the electricity market in the elastic demand case (cont.)

<table>
<tr>
<td>Average Monthly Pool Price</td>
<td>Average monthly pool price is significantly lower after the 33^{rd} month because:
• Total installed capacity in the market is significantly higher, and
• Significantly more small hydro, geothermal and large hydro plants are installed, which have comparatively lower unit production costs.

The pace of change in demand varies less as the average electricity prices of the entire 20 years is almost the same as initial electricity prices in the market. (Therefore, average monthly pool price itself oscillates significantly less as well.)</td>
<td>Because of the reasons explained in the neighboring box, average monthly pool price is significantly higher after the 33^{rd} month.

The pace of change in demand varies more as the average electricity price of the entire 20 year is significantly higher than the initial electricity prices in the market. (Therefore, average monthly pool price itself oscillates significantly more as well.)</td>
</tr>
<tr>
<td rowspan="2">The Effect of Withholding on Average Monthly Pool Price</td>
<td colspan="2">In both scenario sets, withholding results in higher average monthly pool prices.</td>
</tr>
<tr>
<td>• Since higher excess capacity ratio decreases the effect of the withholding on the market, price variations exhibit a smoother nature during the planning horizon.
• Height and frequency of the price spikes are distinctly less.</td>
<td>• The electricity market is distinctly more sensitive to withholding because of lower excess capacity ratio.
• There are distinctly more spikes in the average monthly pool price. Besides, the height of the price spikes is distinctly higher.</td>
</tr>
<tr>
<td>Effect of Withholding on the Profit of Investors</td>
<td>Since electricity market is distinctly less sensitive to withholding, extra profit earned through withholding is distinctly lower.</td>
<td>As explained in the neighboring box, extra profit earned through withholding is distinctly higher.</td>
</tr>
<tr>
<td>Total Installed Geothermal Power Plant Capacity</td>
<td colspan="2">As the initial capacities of existing geothermal plants and geothermal plants under construction are the same in both scenario sets, total installed capacity of geothermal plants remain the same in both scenario sets until the 49^{th} month.</td>
</tr>
</table>

Table 7.8. The effect of different forecast periods on the electricity market in the elastic demand case (cont.)

<table>
<tr>
<td></td>
<td>• New geothermal plants are introduced to the market earlier than they do in the reference scenario (they are introduced to the market after the 48^{th} month in the 6^{th} scenario set, whereas they are introduced to the market after the 96^{th} month in the reference scenario set) since in the 6^{th} scenario set investors' investment decisions are based on a projection of a longer period and the demand in the 6^{th} scenario set is much higher than the demand in the reference scenario set.
• As a consequence, total installed capacity of geothermal plants between 49^{th}-229^{th} months is;
o significantly higher if the investors are conservative;
o distinctly higher if the investors are aggressive.</td>
<td>• As explained in the neighboring box, total installed capacity of geothermal power plants between the 49^{th}-229^{th} months is ;
o significantly lower if the investors are conservative and
o distinctly lower if the investors are aggressive.</td>
</tr>
<tr>
<td rowspan="2">Total Installed Small-Hydro Power Plant Capacity</td>
<td colspan="2">Because of their lowest unit production cost and second lowest investment cost, small-hydro plants are preferred at earlier stages of the planning horizon and are constructed until the end of the first half of the planning horizon, up to the full utilization of national potential.</td>
</tr>
<tr>
<td>• As the investors consider a longer period forward to the future to meet the supply-demand gap; distinctly more small-hydro plant capacity is constructed in earlier stages of planning horizon.
• Total installed small hydro plant capacity increases with jumps.</td>
<td>• As the investors consider a shorter period forward to the future to meet the supply-demand gap; distinctly less small-hydropower plant capacity is constructed in later stages of planning horizon.
• Total installed small hydro plant capacity increases gradually.</td>
</tr>
<tr>
<td>Total Installed Large-Hydro Power Plant Capacity</td>
<td>• As the investors consider a longer forecast period and the demand in the market is much higher than in the counter-scenario set.
o Total installed large hydro plant capacity increases with steep steps.
o Total installed large hydro plant capacity is significantly higher at the end of the planning horizon.</td>
<td>• As explained in the neighbouring box;
o Total installed large hydro plant capacity increases gradually.
o Total installed large hydro plant capacity is significantly lower at the end of the planning horizon..</td>
</tr>
<tr>
<td>Total Installed Natural Gas Power Plant Capacity</td>
<td colspan="2">Natural gas plants are the most preferred among all plant types because they have the lowest investment cost. As a consequence, in both scenario sets, natural gas plants constructed until the 240^{th} month utilizes most of the country's potential. In the 6^{th} scenario set, almost all of the natural gas potential, in the reference scenario set, (except the case with aggressive investors and withholding,) about 90 per cent of the natural gas potential is utilized. (In the presence of aggressive investors and withholding, natural gas potential is fully utilized).</td>
</tr>
</table>

Table 7.8. The effect of different forecast periods on the electricity market in the elastic demand case (cont.)

	As the investors' investment decision is based on a projection of a longer period and the demand in the market is much higher than the demand in the reference scenario set; • Total installed capacity of natural gas power plants increases rapidly with steep steps. • At the end of the 240th month, o In case of withholding and aggressive investors in both scenario sets, almost all of the natural gas potential is utilized, so total installed natural gas plant is almost the same in both scenario sets. o In the remaining scenarios, total installed natural gas plant capacity in the 6th scenario set is much higher as compared to the reference scenario set.	As explained in the neighbouring box; • Total installed capacity of natural gas plants increase gradually. • As explained in the neighboring box, at the end of the 240th month, o In case of withholding and aggressive investors; total installed natural gas plant is almost the same in both scenario sets. o In the remaining scenarios; total installed natural gas plant capacity in the reference scenario set is much lower as compared to the 6th scenario set.
Total Installed Imported Hard Coal Power Plant Capacity	As the investors' investment decision is based on a projection of a longer period and the demand in the market is much higher than it is in the reference scenario set; by the end of the planning horizon, total installed imported hard coal plant capacity is significantly higher.	As explained in the neighbouring box; by the end of the planning horizon, total imported hard coal plant capacity is significantly lower.
Total Installed Capacity of Wind Power Plants	• Since there exists higher reserve margin in the 6th scenario set, monthly pool prices in this scenario set is significantly lower in comparison to the reference scenario set. Besides, in case the investors are aggressive, pool prices are also lower due to lower profit margins of the investors. As a result, when the investors are aggressive, wind plants are less attractive in the 6th scenario set in comparison to the reference scenario set. • As a consequence, at around the 240th month of the planning horizon, total wind plant capacity is lower than it is in the reference scenario set.	• Because of the reasons explained in the neighboring box, at around the 240th month of the planning horizon, total wind plant capacity is higher than it is in the counter scenario set.

Table 7.8. The effect of different forecast periods on the electricity market in the elastic demand case (cont.)

<table>
<tr><td>Total Installed Lignite Power Plant Capacity</td><td>As the investors' investment decisions are based on a projection of the demand and the demand is comparatively much higher, total installed lignite plant capacity is significantly higher during the planning horizon.</td><td>Because of the reasons explained in the neighboring box; total installed lignite plant capacity is significantly lower during the planning horizon.</td></tr>
<tr><td rowspan="2">Total Installed Diesel-Oil Power Plant Capacity</td><td colspan="2">• Because of their highest unit production costs among all plant types, diesel-oil plants are not preferred unless all available potential of other primary energy resources are used up or the price in the market is high.
• Diesel oil plants are installed after the 121st month of the planning horizon, after all available potential of other primary energy resources has been exhausted.
• As average electricity prices of the entire planning horizon in the presence of elastic demand is higher than that of the case in the presence of inelastic demand, total installed diesel-oil plant capacity is much higher , in the presence of elastic demand, in both scenario sets.</td></tr>
<tr><td>Total installed diesel-oil plant capacity is much higher in comparison to the reference scenario set.</td><td>Total installed diesel-oil plant capacity is much lower in comparison to the 6th scenario set.</td></tr>
<tr><td>Profit of the Investors</td><td>As average monthly pool price is lower and height of price spikes are distinctly shorter, cumulative profits of the investors are distinctly lower.</td><td>As explained in the neighboring box, cumulative profits of the investors are distinctly higher.</td></tr>
</table>

Table 7.9. The effect of long-term contracts on the electricity market in the inelastic demand case

	Market with Long-Term Contracts (7th Scenario Set)	**Market without Long-Term Contracts (Reference Scenario Set)**
Peak Demand	Since annual demand growth rate is the same in both scenario sets and demand is inelastic, peak demand is the same in both scenario sets.	
Total Installed Capacity	• Since, during the most of the planning horizon, average pool price in the 7th scenario set is much lower than that of the case in the reference scenario set, the electricity market in the 7th scenario set is not attractive for the investors as much as the electricity market in the reference scenario set. • As a result of this, total installed capacity in the 7th scenario set is much lower than total installed capacity in the reference scenario set during most of the planning horizon and at the end of 20 years. • On the other hand, some of the years it is observed that total installed capacity in the 7th scenario set is much more than total installed capacity in the reference scenario set because of the following factors; o In the 7th scenario set new power plants are introduced to the market earlier than that of the case in the reference scenario set. Since; o As a result of lower electricity prices in the 7th scenario set as compared to the reference scenario set, in the 7th scenario set, some of the plant types (having high investment costs) are not attractive for the investors as much as the case in the reference scenario set. Consequently, during some periods, in the 7th scenario set, investors invest in natural gas power plants more than the case in reference scenario set. o Besides, natural gas plant's construction time is lower than most of the other plant types' construction time so, plant portfolio under construction became active earlier than the case in the reference scenario set.	• As explained in the neighboring box; Total installed capacity in the reference scenario set is much higher than that of the case in the 7th scenario set during most of the planning horizon and at the end of planning horizon. • Ratio of the large-hydro, lignite and geothermal plants in the new investment portfolio of the investors in the reference scenario set is much more than the ratio in the 7th scenario set. On the other hand, construction times of lignite, geothermal and hydro plants are longer than that of natural gas plants. As a consequence, some of the years, total installed capacity in the reference scenario set lags behind total installed capacity in the 7th scenario set.

Table 7.9. The effect of long-term contracts on the electricity market in the inelastic demand case (cont.)

<table>
<tr><td rowspan="2">Average SMP</td><td>Since the portion of the total demand supplied by the pool is lower, average SMP is slightly lower.</td><td>As explained in the neighbouring box, average SMP is slightly higher.</td></tr>
<tr><td colspan="2">• Since the small hydro plants (having the lowest unit production cost) constructed throughout the planning horizon, gradually enters to the market between the 61^{st} and the 121^{st} months, average SMP decreases during this period.
• After the 121^{st} month, average SMP remains almost constant, since new large hydro plants (having unit production cost similar to the small-hydro plants) are introduced to the market after the small ones.</td></tr>
<tr><td rowspan="2">Average Monthly Pool Price</td><td colspan="2">• At the beginning of the planning horizon, there is almost no excess supply in the market and not enough plant under construction to meet the next 3 years' demand. As a result, electricity reserve margin decreases gradually during the first five years. Consequently, average electricity price increases during the first five years of the planning horizon.
• Since after the 61^{st} month, new small hydro plants (having low unit production cost) are gradually introduced to the market, total installed capacity and electricity reserve margin increases. Consequently, average monthly pool price decreases until the 205^{th} month.
• Average electricity price of the entire planning horizon increases again between around 229^{th} and 240^{th} months, as electricity reserve margin decreases.
• Average electricity price of entire 20 years is distinctly higher than the average electricity prices seen in the first years of the planning horizon.
• As compared to the scenarios without withholding, the electricity price in both of the scenario sets is distinctly higher in the scenarios with withholding.</td></tr>
<tr><td>• In case there is no withholding; since a portion of the total demand is met by long-term contracts in the market, demand supplied by the pool is much lower than that of the case in the reference scenario set, average electricity price of 20 years in the 7^{th} scenario set is much lower than that of the case in the reference scenario set.
• In case there is withholding; the amount of the demand that is prone to be effected by the presence of the withholding is much lower, since a portion of the demand is guaranteed to be supplied at a predetermined price. As a result;
o height of the price spikes, caused typically by withholding, is distinctly shorter in comparison to the reference scenario set.
o in the 7^{th} scenario set, average electricity prices observed throughout the entire planning horizon is significantly lower than that of the case in the reference scenario set.</td><td>As explained in the neighboring box,
• In case there is no withholding; average electricity price of 20 years in the reference scenario set is much higher than that of the case in the 7^{th} scenario set.
• In case there is withholding;
o height of the price spikes, which typically occurs because of withholding, is distinctly longer than the price spikes in the 7^{th} scenario set.
o average electricity prices observed throughout the entire planning horizon in the reference scenario set is significantly higher than that of the case in the 7^{th} scenario set.</td></tr>
</table>

Table 7.9. The effect of long-term contracts on the electricity market in the inelastic demand case (cont.)

Cumulative Profit of the Investors	• Long-term contract in a market is a safe-guard against investors' risk of selling less than their capacities (especially, when the reserve margin in the market is high). On the other hand, in case there is shortage in the market, long-term contract behaves as a safeguard for the consumers rather than the investors, since in such an environment investors do not have risk of selling below their capacities at a low price (because in case of supply shortages in the market, investors can sell as much as they can generate and electricity shortages bring about high prices in the market.) • In the scenarios considered in this study, electricity reserve margin is low, due to this reason in case there is no long-term contract in the market, investors are more able to benefit from high price spikes and high pool prices. As a result of the factors forwarded above, o In case there is no withholding in the market; Investors' cumulative profit in the 7th scenario set is significantly lower than the case in the reference scenario set. o In case there is withholding in the market; in the 7th scebario set, as the investors are less able to benefit from the high price spikes which resulted from capacity withholding of the investors, the investors' cumulative profit, at the end of the 20th year, is distinctly lower than the profit obtained in the reference scenario set.	As explained in the neighboring box; • In case there is no withholding in the market; investors' cumulative profit in the reference scenario set is significantly higher than cumulative profit in the 7th scenario set. • In case there is withholding in the market; in the reference scenario set, investors' cumulative profit at the end of 20th year is distinctly higher than the case in the 7th scenario set.
Monthly Profit of the Investors	• The investors are significantly less adversely impacted by the price fluctuations in the pool, as they introduce less amount of electricity to the pool than their overall capacity. • As a result, monthly profit fluctuations are less than that of the case in the reference scenario set.	• Since there is no agreement with customers, which guarantee the amount of electricity that investors will sell, and the sales price; the profit of the investors in the reference scenario set oscillates much more than it does in the 7th scenario set

Table 7.9. The effect of long-term contracts on the electricity market in the inelastic demand case (cont.)

<table>
<tr><td>Total Installed Small-Hydro Power Plant Capacity</td><td colspan="2">Because of their lowest unit production cost and second lowest investment cost,small hydro plants are constructed almost until the end of the first half of the planning horizon, until all the available national potential is utilized.</td></tr>
<tr><td>Total Installed Large-Hydro Power Plant Capacity</td><td>• In case there is no withholding;
As previously explained in detail, in the 7th scenario set, pool prices are lower than that of the reference scenario set. As a result, in the 7th scenario set, investing in more capital intensive plant types (than small-hydro and natural gas plants) is not as attractive as the case in the reference scenario set.
Therefore, in the 7th scenario set, total installed large hydro plant capacity is distinctly lower as compared to the reference scenario set.
• In case there is withholding;
o Due to withholding, electricity prices and consequently expected electricity prices increases.
o As a result, although long-term contracts in a market causes electricity prices low to build large-hydro plants, with the effect of withholding; electricity prices become high enough to build large-hydro plants.
o Besides, the supply-demand gap in the 7th scenario set is higher than that of the case in the reference scenario set;
Because of the factors forwarded above, total installed large-hydro power plant capacity in the 7th scenario set is ;
o In case the investors are aggressive;
much more than the related scenario in the reference scenario set.
o In case the investors are conservative;
nearly the same as the related scenario in the reference scenario set.</td><td>As explained in the neighboring box;
• In case there is no withholding;
in the reference scenario set, total installed large hydro plant capacity is distinctly higher as compared to the 7th scenario set.
• In case there is withholding;
total installed large-hydro power plant capacity in the reference scenario set is ;
o In case the investors are aggressive;
much lower than the related scenario in the 7th scenario set.
o In case the investors are conservative;
nearly the same as the related scenario in the 7th scenario set.</td></tr>
</table>

Table 7.9. The effect of long-term contracts on the electricity market in the inelastic demand case (cont.)

<table>
<tr><td rowspan="2">Total Installed Natural Gas Power Plant Capacity</td><td colspan="2">Natural gas plants are preferred over other plant types because of their lowest investment cost. As a consequence, almost all available national potential for natural gas plants is utilized until the 240th month.</td></tr>
<tr><td>As the pool price in the market is much lower, expected pool price in the market is also much lower. Therefore, more capital intensive plant types in comparison to natural gas and small-hydro plants are not constructed/preferred by some investors as much as they are preferred in the reference scenario set. As a consequence, in the 7th scenario set, investors prefer to invest in natural gas plants more than they do in the reference scenario set. Due to this reason, in some months during the planning horizon, total installed natural gas plant capacity is much higher in comparison to the reference scenario set.</td><td>As explained in the neighboring box; total installed natural gas power plant capacity is much lower in comparison to the 7th scenario set.</td></tr>
<tr><td>Total Installed Imported Hard-Coal Power Plant Capacity</td><td>• Pool price in the market is much lower;
o Therefore, in the 7th scenario set, investors perceive imported hard-coal plants less attractive than they do in the reference scenario set.
o As a consequence, in comparison to the reference scenario set, fewer imported hard coal plant is constructed during the planning horizon.</td><td>As explained in the neighboring box, In comparison to the 7th scenario set, total installed imported hard coal plant is much higher during the planning horizon</td></tr>
<tr><td>Total Installed Wind Power Plant Capacity</td><td>Due to lower pool prices, no new wind plant is introduced to the market, until the end of 20 years.</td><td>In the scenario with aggressive investors and no withholding in the reference scenario, total wind power plant capacity introduced to the market is approximately one per cent of the national potential. In the remaining scenarios in the reference scenario set, no new wind power plant is introduced to the market during entire planning horizon.</td></tr>
<tr><td>Total Installed Lignite Power Plant Capacity</td><td>As explained previously, pool prices and consequently expected pool prices in the market is much lower in comparison to that of the case in the reference scenario set. Therefore, in the 7th scenario set, total installed lignite power plant, (having high investment cost), capacity is much lower in comparison to the reference scenario set.</td><td>As explained in the neighboring box; total installed lignite power plant capacity is much higher in comparison to the 7th scenario set.</td></tr>
</table>

Table 7.9. The effect of long-term contracts on the electricity market in the inelastic demand case (cont.)

Market Share of the Investors	• The investors have the guarantee of definitely selling some portion of their capacity according to prevailing long-term contracts. As a consequence, the capacity offered to the pool by the investors is lower than their available capacity. Therefore, variation in investors' market share in time is much lower than that of the case in the reference scenario set. • Since presence of long-term contract in the market results in lower pool prices, the investors hesitate to increase their capacity/to enter the market. Because of this reason, as it is previously stated, in the 7th scenario set total installed capacity is much lower so, ratio of Incumbent's total installed capacity to the overall installed capacity is much higher as compared to the reference scenario. As a result, Incumbent's market share is much higher as compared to the reference scenario set. In other words, Incumbent's market power prevails in the market for a long time.	• In the absence of long term contracts, the investors are highly prone to the risks of the pool mechanism such as not being able to sell as much as they had presumed, if any, due to the composition of competitors' plant portfolio or due to competitors' bid prices offered to the pool. As a result, variation in investors' market share in time is much higher than that of the case in the counter scenario set. • In the absence of long-term contract, electricity prices are higher. Due to this reason, investors construct more plants than they do in a market with long-term contract. Because of this reason, as it is previously stated, total installed capacity and also total installed capacity of IPPs and NE is much higher. As a result, in the reference scenario set, Incumbent's market share is much lower as compared to the 7th scenario set.

Table 7.10. The effect of long-term contracts on the electricity market in case in the elastic demand case

	Market with Long-Term Contracts (7^{th} Scenario Set)	**Market without Long-Term Contracts (Reference Scenario Set)**
Peak Demand	Thanks to the long-term contracts in the market, pool price exhibits lower values especially in the first half of the planning horizon as compared to the reference scenario set. As a result, average peak demand in the 7^{th} scenario set is higher than that of the case in the reference scenario set, during the second half of the planning horizon.	As explained in the neighboring box; During the second half of the planning horizon, peak demand in the reference scenario set is lower than peak demand in the 7^{th} scenario set.
Total Installed Capacity	• As a result of the lower pool prices (especially in the first half of the planning horizon), until the end of the 169^{th} month, total installed capacity in the 7^{th} scenario set is much lower than total installed capacity in the reference scenario set. • Finally, at the end of the 240^{th} month, total installed capacity in the 7^{th} scenario set is higher than the value in the reference scenario set due to the following reasons; o Reserve margin the 7^{th} scenario set is much lower than that of the case in the reference scenario set, since; ➢ Peak demand in the 7^{th} scenario set is higher as compared to the reference scenario set, during the second half of the planning horizon. ➢ Until the end of the 169^{th} month, total installed capacity in the 7^{th} scenario set is lower as compared to the reference scenario set. Due to the reserve margin figures, capacity payment (product of VOLL and LOLP) paid by the Regulator to the investors is much higher as compared to the reference scenario set. As a result, despite the presence of the long-term contract in the market reduces pool prices, capacity payments bring about more attractive market for the investors in comparison to the reference scenario set, during the second half of the planning horizon.	As explained in the neighboring box; • Until the end of the 169^{th} month, total installed capacity in the reference scenario set is much higher than total installed capacity in the 7^{th} scenario set. • At the end of the 240^{th} month, total installed capacity in the reference scenario set is lower than that of the case in the 7^{th} scenario set.

Table 7.10. The effect of long-term contracts on the electricity market in case in the elastic demand case (cont.)

<table>
<tr>
<td rowspan="2">Average Monthly Pool Price</td>
<td colspan="2">In both scenario sets, as there is price elastic demand, an increase in price triggers a decrease in demand after a while. The decrease in demand results in a decrease in price which in turn causes, after a period, the demand to increase. This sequential reaction, which is typically observed in elastic demand case, boosts the annual and monthly price variations in the market.
Average pool prices observed during entire planning horizon is distinctly higher than the average pool prices observed at the earlier stages of the planning horizon.</td>
</tr>
<tr>
<td>• As a portion of the demand is met by long-term contracts in the market, demand supplied by the pool is significantly lower than the case in the reference scenario set. As a consequence, in the 7^{th} scenario set, average monthly pool price is much lower until the 133^{rd} month as compared to the reference scenario set.
• As it is previously stated, during the second half of the planning horizon, peak demand in the 7^{th} scenario set is higher than the value in the reference scenario set. Therefore, average monthly pool price in the 7^{th} scenario set is nearly the same as or sometimes higher than the case in the reference scenario set, after the 133^{rd} month.
• If there is withholding in the market, the amount of the demand that is prone to be effected by the presence of the withholding is much lower than the reference scenario set thanks to the long-term contracts in the market.
As a consequence,
o the height of the price spikes caused by withholding is distinctly lower as compared to the reference scenario set. (i.e. the impact of withholding on the electricity market is distinctly less in case there is long-term contract in the market)
• Average of the pool prices throughout the planning horizon is;
o In case there is withholding; significantly lower as compared to the reference scenario set;
o In case there is no withholding;
slightly lower as compared to the reference scenario set.</td>
<td>As explained in the neighboring box;
• In the reference scenario set, average monthly pool price is much higher until the 133^{rd} month as compared to the 7^{th} scenario set.
• Average monthly pool price in the reference scenario set is nearly the same as or sometimes higher than the case in the 7^{th} scenario set, after the 133^{rd} month.
• In case there is withholding in the market,
o the height of the price spikes caused by withholding is distinctly higher as compared to the 7^{th} scenario set.
• Average of the pool prices throughout the planning horizon is;
o In case there is withholding;
significantly higher as compared to the reference scenario set;
o In case there is no withholding;
slightly higher as compared to the reference scenario set.</td>
</tr>
<tr>
<td>Total Installed Small-Hydro Power Plant Capacity</td>
<td colspan="2">Because of their lowest variable and second lowest investment costs among the other plant types, small hydro plants are constructed almost until the end of the first half of the planning horizon, until all the national potential is utilized.</td>
</tr>
</table>

Table 7.10. The effect of long-term contracts on the electricity market in case in the elastic demand case (cont.)

Total Installed Large-Hydro Power Plant Capacity	• Large-hydro plants have long construction time and high investment costs. • Since electricity prices are much lower as compared to the reference scenario set until the end of the 133rd month, large-hydro plants are not perceived as attractive as they are in the reference scenario set. As a result, throughout the first 12 years, investors, in the 7th scenario set, invest less on large-hydro plants as compared to the reference scenario set. (Except when there is withholding and the investors are aggressive, since withholding raises the prices in the market and conservative investors' profit margin is high, then the pool price, in such a case, still fosters large-hydro plant investments in the 7th scenario set) • The discussion presented below is valid for the scenarios excluding the cases with conservative investors and withholding; Although, after the 133rd month, thanks to the higher peak demand and lower reserve margin in the market, pool prices are nearly the same as the case in the reference scenario set, so investors perceive the large-hydro plants as attractive as the case in the reference scenario. However, since the construction time of these plants are long, most of them can't be on line until the end of the planning horizon. • As a consequence, total installed large hydro plant capacity ; o In all scenarios, excluding the case with conservative investors and withholding; ➢ is much lower in the 7th scenario set as compared to the reference scenario set. o In case with conservative investors and withholding; ➢ is slightly higher in the 7th scenario set as compared to the case in the reference scenario set.	As explained in the neighboring box; • Total installed large hydro plant capacity in the reference scenario set; o In all scenarios, excluding the case with conservative investors and withholding; ➢ is much higher as compared to the 7th scenario set. o In case with conservative investors and withholding; ➢ is slightly lower as compared to the case in the 7th scenario set.

Table 7.10. The effect of long-term contracts on the electricity market in case in the elastic demand case (cont.)

<table>
<tr>
<td rowspan="2">Total Installed Natural Gas Power Plant Capacity</td>
<td colspan="2">Natural gas plants are preferred distinctly more than other plant types because of their lowest investment cost among all other plant types. As a consequence, in both scenario sets, natural gas plants are constructed up to the full country's potential until the end of the planning horizon.</td>
</tr>
<tr>
<td>• As discussed before, in the 7^{th} scenario set, pool price and consequently expected pool price is much lower until the 133^{rd} month, as compared to the reference scenario set.

As a consequence, in the 7^{th} scenario set, some plant types (having high investment costs) are unattractive for the investors. Therefore, in the 7^{th} scenario set, investors invest on more restricted types of plants during the first 133 months.

• Investors, in the 7^{th} scenario set, are much less willing to invest in more capital intensive power plant types, in comparison to natural gas and small-hydro power plants, but very much eager to invest in natural gas power plants, compared to the reference scenario set.

• So, during the most of the first 3 quarter of the planning horizon, total installed natural gas plant capacity in the 7^{th} scenario set is much more than that of the case in the reference scenario set, especially when the investors are conservative.</td>
<td>• Especially when the investors are conservative, throughout the first 3 quarter of the planning horizon, total installed natural gas plant capacity is much less than the case in the 7^{th} scenario set.
Because; in a market without long term contracts, electricity prices are higher and the investors have the opportunity to constitute a plant portfolio of many different plant types in order to minimize potential risks. In other words, investors do not concentrate on only one/two specific plant type such as natural gas plants but prefer to invest in other plant types as well.</td>
</tr>
<tr>
<td>Total Installed Imported Hard-Coal Power Plant Capacity</td>
<td>Because the demand exhibits higher values throughout the planning horizon, total installed imported hard-coal plant capacity is much higher in the 20^{th} year as compared to the reference scenario set.</td>
<td>As explained in the neighboring box;
Total installed imported hard-coal power plant capacity is much lower in the 20^{th} year as compared to the 7^{th} scenario set.</td>
</tr>
<tr>
<td>Total Installed Lignite Power Plant Capacity</td>
<td>After the first half of the planning horizon, total installed lignite plant capacity in the 7^{th} scenario set is much higher than it is in the reference scenario set.</td>
<td>After the first half of the planning horizon, total installed power plant capacity in the reference scenario set is much lower than it is in the 7^{th} scenario set</td>
</tr>
</table>

Table 7.10. The effect of long-term contracts on the electricity market in case in the elastic demand case (cont.)

Total Installed Wind Power Plant Capacity	Since demand in the 7th scenario set is much higher than the case in the reference scenario set during the second half of the planning horizon, • In the 7th scenario set, total installed wind plant capacity at the end of the 20th year is; o much higher if the investors are aggressive, o much higher if the investors are conservative and there is withholding, • On the other hand, if the investors are conservative and there is no withholding, total installed wind plant capacity at the end of 20 year is much lower as compared to the reference scenario set. Because; o Conservative investors' ROR expectations from new investments are high and existence of long-term contract in the market results in lower pool prices. Besides, due to absence of withholding, there is no high price spikes, which motivate investors invest more on plants with high investment cost.	As explained in the neighboring box; • In the reference scenario set, total installed wind plant capacity at the end of the 20th year is; o much lower in case the investors are aggressive, o much lower in case the investors are conservative and there is withholding, • In case the investors are conservative and there is no withholding, total installed wind plant capacity at the end of 20 year is much higher as compared to the 7th scenario set.
Market Share of the Investors	The investors have the guarantee of definitely selling some portion of their capacity owing to their prevailing long-term contracts. As a consequence, the capacity offered to the pool by the investors is much lower than their available capacity. As a result, variation in the investors' market share during the planning horizon is distinctly lower.	In the absence of long term contracts, the investors are highly prone to the risks of the pool system such as not being able to sell as much as they had presumed, due to the composition of competitors' power plant portfolio or due to competitors' bid prices. As a result, variation in the investors' market share during the planning horizon is distinctly higher.

Table 7.11. The effect of tax exemption on the electricity market in the inelastic demand case

<table>
<tr><th></th><th>Tax Exemption 40 %
(Reference Scenario Set)</th><th>No Tax Exemption
(8^{th} Scenario Set)</th></tr>
<tr><td>Peak Demand</td><td colspan="2">Since the annual demand growth rate is the same in all scenario sets and demand is inelastic, peak demand is the same in both of the scenario sets.</td></tr>
<tr><td>Total Installed Capacity</td><td>In case of tax exemption, the investors are not asked to pay any tax unless their cumulative profit exceeds the prescribed portion of the investment cost. So, tax exemption acts as an investment incentive especially for more capital intensive power plant types. As a result, total installed capacity in the reference scenario set is higher than that of the case in the 8^{th} scenario set.</td><td>As explained in the neighboring box;
Total installed capacity is lower than that of the case in the reference scenario set.</td></tr>
<tr><td>Average SMP</td><td colspan="2">Small-hydro plants are decided to be constructed earlier than other plant types. They are introduced to the market gradually between the 61^{st} and 121^{st} months. As a consequence, average SMP gradually decreases between these months. After this period, though, SMP remains almost constant as a result of the contribution of the large- hydro plants introduced to the market.</td></tr>
<tr><td rowspan="2">Average Monthly Pool Price</td><td colspan="2">The average electricity price of entire planning horizon is much higher than initial pool prices.</td></tr>
<tr><td>As a result of tax exemption,
• As compared to the natural gas and small-hydro plants, more capital plant types (especially large-hydro plants) become more attractive for the investors.
• Besides, since hydro plant's variable cost is low, average monthly pool price in the reference scenario set is lower.</td><td>As a result of absence of tax exemption, plant types having low variable and high investment costs are preferred less than that of the case in the reference scenario set. As a consequence, average monthly pool price is higher.</td></tr>
<tr><td>Effect of Withholding on Average Monthly Pool Price</td><td colspan="2">In the scenario sets, in case of withholding, average monthly pool prices assume distinctly higher values compared to the scenarios without withholding.</td></tr>
<tr><td rowspan="2">Total Installed Geothermal Power Plant Capacity</td><td colspan="2">Since the country's potential for natural gas and small-hydro plants suffices to meet the demand until the 80^{th} month, no new geothermal plants are introduced to the market throughout this time period.</td></tr>
<tr><td>For the investors, geothermal plants are more attractive, since tax exemption acts as an incentive. As a consequence, after the 97^{th} month, total installed geothermal plant capacity is much higher than that of the case in the 8^{th} scenario set.</td><td>Investors are asked to pay tax, before a prescribed portion of their investment has been paid back which renders capital intensive investments less attractive to investors in comparison to the market with tax exemption.
As a consequence, after the 97^{th} month, total installed geothermal plant capacity is much lower than that of the case in the reference scenario set.</td></tr>
</table>

Table 7.11. The effect of tax exemption on the electricity market in the inelastic demand case (cont.)

<table>
<tr><td>Profit of the Investors</td><td>Investors' cumulative net profit at the end of planning horizon is distinctly higher, since the investors do not pay taxes before a prescribed portion of their investment has been paid back.</td><td>Investors' cumulative net profit at the end of planning horizon is distinctly lower as they had to pay tax just after their power plants are introduced to the market.</td></tr>
<tr><td>Total Installed Small-Hydro Power Plant Capacity</td><td colspan="2">Small-hydro plants, having the lowest variable and comparatively low investment costs among all the other plant types, are always attractive for investors regardless of the presence of tax exemption. Therefore, until the 10^{th} year of the planning horizon, small-hydro plants are intensively constructed, by utilizing all the country's potential.</td></tr>
<tr><td rowspan="2">Total Installed Large-Hydro Power Plant Capacity</td><td colspan="2">In the scenario sets, the increase in the pool price between 1^{st} -97^{th} months is followed by a decrease between 98^{th} –193^{rd} months. The price in this period is the lowest price along the entire planning horizon, causes large hydro plants to be unattractive to invest in.</td></tr>
<tr><td>• As tax exemption acts as an incentive, though, all investors invest in large-hydro plants.
• Total installed capacity of large-hydro plants is much higher than that of the case in the counter scenario set until the 240^{th} month.</td><td>• Although expected electricity prices in the 8^{th} scenario set are slightly higher than that of the case in the reference scenario set, due to absenteeism of tax exemption, investors invest less in large hydro plant as compared to the reference scenario set.
• As a result, total installed capacity of large-hydro plants in the 8^{th} scenario set is much lower than that of the case in the reference scenario set until the 240^{th} month.</td></tr>
<tr><td rowspan="2">Total Installed Natural Gas Power Plant Capacity</td><td colspan="2">Natural gas plants are preferred over other plant types because of their lowest investment cost. As a consequence, in both scenario sets, all available natural gas potential is utilized until the 240^{th} month.</td></tr>
<tr><td>• Thanks to the tax exemption, investors invest in more capital intensive (as compared to the natural gas and hydro-small) plants as well.
o Therefore, during intermediate years, investors invest less in natural gas plants in comparison to the 8^{th} scenario set.
o As a result, total installed natural gas plant in the reference scenario set is much lower than that of the case in the 8^{th} scenario set between the 121^{st} - 217^{th} month.
o After the 217^{th} month, difference between two scenario sets is closed since there is no more natural gas potential to build new plants.</td><td>Because of the reasons sited in the neighboring box;
o Total installed natural gas plant in the 8^{th} scenario set is much higher between the 121^{st} -217^{th} months.
o After the 217^{th} month, total installed natural gas power plant capacity is the same in both scenario sets.</td></tr>
</table>

Table 7.11. The effect of tax exemption on the electricity market in the inelastic demand case (cont.)

Total Installed Imported Hard Coal Power Plant Capacities	Total installed capacity of imported hard-coal power plants is higher at the end of the planning horizon, since tax exemption acts as an investment incentive.	In case of no tax exemption, rate of return of the imported hard coal plant investments is lower which in turn renders lower total installed imported hard coal power plant capacity in the market.
Total Installed Wind Power Plant Capacity	As the investment and variable costs of wind plants are comparatively higher than other plant types, no investment is made in wind plants throughout the planning horizon. (There is an exceptional scenario in the reference scenario set, with aggressive investors and no withholding. In this scenario, total wind plant capacity introduced to the market is approximately one per cent of the national potential.)	
Total Installed Lignite Power Plant Capacity	If the investors are aggressive almost the same amount of lignite plant is introduced to the market until the end of the planning horizon.	
	If the investors are conservative, total installed lignite plant cpacity is higher at the end of the planning horizon, as tax exemption acts as an investment incentive.	Because of the reason explained in the neighboring box; in case of conservative investors, total installed lignite plant capacity in the 8th scenario set is lower than that of the case in the reference scenario set.
Market Share	Since there is tax exemption, plant investments are much attractive for the investors. (i.e. there is more competition). As a result, market share of Incumbent in the reference scenario set, is lower than market share of Incumbent in the 8th scenario set, during most of the planning horizon.	Because of the reason sited in the neighboring box; market share of the Incumbent in the 8th scenario set is higher than that of the case in the reference scenario set.

8. THE LIBERALIZED ELECTRICITY MARKET MICROWORLD

8.1. Introduction

A Microworld, often called a management flight simulator, has become the generic name for a class of "what-if" tools, involving user-friendly interfaces and providing for strategic decision makers and planners different types of reports containing information on a wide range of aspects.

Recently business simulators (microworlds) have gained importance in management education and policy making processes of the decision makers. A main criticism of traditional case studies is that users cannot see the consequences of their recommendations or test alternative policies and strategies. So, users of such cases do not completely realize the benefits of case-based learning, which is inherently linked to the historical experience of failures and successes and the exploration of different courses of actions. Three learning methods (case-based learning, simulation method, and action learning) are inquired in (Jennings, 2002). In this study, it is stated that the participants rated the simulation method as superior to the action learning and case-based learning methods.

Additionally, systems that human beings directly interact are almost always complex. The complexity of the systems comes from their four characteristics.(Sterman, 1989; Langely and Morecroft, 2004; Powersim, 1997). The first reason of the complexity (of the system) is the dynamic structure of the system itself. The second source of complexity results from the delays within the system. Delays inherent in systems, lead to oscillations and instabilities, as a result of which understanding of the system by decision makers deteriorates. The third property making systems complicated is the existence of feedback mechanisms that either strengthen or reduces the effects of the actions of the decision makers (i.e. existence of balancing and reinforcing feedback loops in the systems). The last source of the complexity is that most of the relations between system components are nonlinear. Due to this property, some of the variables influence the others non-proportionally. Consequently, after a period, the system behavior may change unexpectedly and the decision maker may have problem in understanding the system. On the other hand, dynamics of some systems change continuously, as a result of which history becomes irrelevant as time passes.

Due to the reasons explained above, effective decision support tools are needed to extend the decision makers' knowledge and understanding of the system under consideration. As previously stated, computer simulation models provide flexible platforms for supporting learning the dynamics of the systems (Spector et al., 2001). With microworlds, users have the opportunity to artificially execute their policies and observe the potential impacts of their policies on the system over a long time period. Competition and limited information flow, among teams of users can also add a gaming dimension to the exercise. The learning potential of microworlds can be improved by analyzing and reporting the relation between the performance of teams to their policies and the underlying structure of the business problem. The studies in (Senge and Lannon, 1990) and (Morecroft 1988) are the case studies supported with computer simulations. (Langley and Morecroft, 2004) present an experiment with the global oil microworld. In this study the authors explore the effects of various types of feedbacks on individual learning (outcome feedback and structure feedback). Results suggest that structure feedback positively influences the understanding of the problem and time for the task completion.

Due to the reasons cited above, the proposed SD model, explained throughout Chapter 5, is decided to be converted to a microworld. To accomplish this aim, the following steps are followed in this phase of the study.

First, the variables to be controlled by the player are determined. Then, the SD model is modified in order to allow for fast, accurate and interactive inputting by assigning sliders, switches and graphical input devices to some of the converters Then, by adding a user-friendly interface to the model, the decision making tool (LEMM) is completed. Finally, the LEMM's functionality, effectiveness, practicality and educational capabilities are tested on 26 students of the senior level "Energy Policy and Planning" course at Sabanci University, in the Spring 2006 semester.

8.2. The Liberalized Electricity Market Microworld

8.2.1. Capabilities and Limitations of the LEMM

The LEMM is a valuable tool to be used in understanding, investigating and experimenting on a decentralized and liberalized electricity market, especially in regard to investor behavior, supply, demand and price fluctuations, short and long term effects of various decisions (such as investment decisions, profit margins, capacity withholding, long-term contracts, subsidies/surcharges, VOLL, taxes etc.) and resource limitations. The LEMM offers, in effect, an experimental laboratory for public authorities, energy companies, large consumer groups and researchers for teaching, training, learning, policy design, market testing, and experimental research. In other words, by running the LEMM, users can experiment with different strategies, in order to gain an understanding of the consequences of their actions and dynamics of the electricity market. During an experiment, the LEMM provides the decision makers with different reports, containing information on a wide range of economic, operational, competitive, and strategic aspects of the electricity market.

The user of the LEMM can select for himself/herself the role of the Incumbent, the NE, an IPP or the Regulator. Then he/she sets goals, define strategies and market environment (in terms of financial parameters, resource limitations, investors' aggression levels, presence of withholding and long-term contracts etc.), and finally observe their combined long term effects, by running the LEMM over a 20 year planning horizon. Alternatively, the LEMM user can just set the parameters related with the market environment and all the players, and then launch the LEMM without selecting any active role for himself/herself (i.e. using predetermined decision rules for each player), and then obtain, analyze and compare the scenarios such formulated, to understand the behavior and progress of the industry.

Unfortunately, since Stella 7 R does not support web-based and network-based games, the LEMM can not be simultaneously played by multiple active players using multiple terminals,. As a consequence, throughout each experiment at the Sabanci University, there was only one active player during a simulation run (i.e. the remaining players were driven by the computer itself.) On the other hand, one way to partially create a multiple player environment in the LEMM is having different players providing the decision policy parameters and characteristics of different passive player. Additionally, it should be noted that, LEMM can also be played by multiple active players, if all the players use the same computer and define their strategies and policies at each pause.

The LEMM pauses if the active investor goes bankrupt, and simultaneously a warning message is posted on the screen, to inform the player about this bankruptcy and then the simulation terminates.

The LEMM features a user-friendly interface enabling the user to easily set/reset the parameters and decision variables at the beginning of the planning horizon and at each five year pause. It should be stated that, although throughout the experiment at Sabanci University, five year pause interval was chosen, the LEMM can be set to pause at intervals shorter/longer than five years.

8.2.2. The Interface of the LEMM

As the LEMM considers an extensive range of attributes (such as long-term contracts, withholding, primary energy resources' reserves, CO_2 tax, default decision rules of passive players, active player's decision, financial issues, demand side of the electricity market, initial capital structure and power plant portfolio of the investors, features of up to eight different power plant types) important in the electricity market, there exists a wide range of parameters and decision variables that the LEMM-user may desire to check (and decide to leave at their default values or to reset to one of the many alternative values) throughout the planning horizon. Because of this reason, decision variables and parameters than can be set/reset via the user interface of the LEMM are displayed in groups on the input screens of the LEMM (and each preset to a carefully selected initial default value), so that the LEMM-user does not waste considerable amount of time by exploring through screens or inputting unnecessary/repetitive information. The parameters and decision variables that can be defined via the user interface of the LEMM, and the related screens are presented below.

The first screen of the LEMM is the “Main Menu”, which is presented in Figure 8.1. As can be observed from Figure 8.1, the LEMM-user is directed to the “Info Screen”, (displayed in Figure 8.2), if he clicks on the Info button. The Info Screen briefly explains the main objectives and the general structure of the game, and the general characteristics of the player types. The LEMM-user may use the scroll down button to move within the “Info Screen”. If the LEMM-user clicks on the “SET-UP” button displayed on the “Main Menu”, he is directed to the “Set-up Screen”, illustrated in Figure 8.3.

Regulatory issues, financial terms, demand issues and plant related parameters are inputted by using the input devices integrated on the related LEMM screen presented in Figure 8.4. All of the input devices on this screen, (except the LOLP and the hourly-load curve) are slider type, which enables the user set the values of the parameters and decision variables just by moving the slider’s knob. The parameters and decision variables that can be reset by using these sliders are presented in Figure 8.4, and there is no need to further discussion. Additionally, a restore button, at the lower left corner of the slider device, appears whenever the slider's knob is moved; clicking the restore button causes the slider's value to be restored to its default value. Actually, a restore button is available on all types of input devices used in the LEMM and their functions are all similar (restoring the default value of the parameter when selected).

As illustrated in Figure 5.10, there exists a default LOLP function in the LEMM. Besides, as presented in Figure 8.4, the LEMM-user is able to change the LOLP values, just by double-clicking on the graphical input device. Then, the LEMM-user opens the related dialog box, and is able to reset the LOLP by dragging on the default LOLP graph.

As illustrated in Figure 8.4, there are two different scenario options for the hourly load curve, which can be activated by ticking the related option. The first option, (the default hourly load curve) includes the default ratios, explained in Section 5.2.4 and illustrated in Table 5.2. In the second option, which is called as “more intensive hourly load curve”, the ratio of electricity demand to annual peak demand, is higher than that of the default case. The ratios implemented in the second option are presented in Table 8.4.

Next, the LEMM-user is led to the “Plant Screen”, (by pushing the “Plant Data” button). The Plant Screen, presented in Figure 8.5, consists of input devices designed for resetting the values of CO_2 emission, construction times and variable costs of power plant types. The LEMM-user is directed to another screen (presented in Figure 8.6) to reset capacity factors and availability factors of the power plant types.

Primary energy resources’ reserve, initial power plant portfolio, initial capital of the investors, and capacity cost of power plant types are defined via the screen presented in Figure 8.7. As it can be observed from Figure 8.7 and Figure 8.8, four different (built-in) initial power plant portfolios are available for each investor type. Additionally, if the LEMM-user desires, he/she can enter his/her own choice of initial power plant portfolio (as long as the primary energy resource’s reserve is not violated by the selected set of plants).

Through the screen displayed in Figure 8.9, the LEMM-user can define the aggression level and profit margin of the investors, the forecast period used in projecting the demand and pool price, presence of withholding and long-term contracts in the market, the initial long-term contract price (in case the long-term contract option is activated), presence of seasonality effect on wind and hydro power plants’ capacity factors and annual capacity limit on power plant types.

Active investor’s decisions are defined by the LEMM-user via the screen displayed in Figure 8.10. If the LEMM-user selects one of the investors’ role, then he defines his debt ratio in new investments, his total investment amount (MW) and the distribution of this amount to the power plant types, the portion of his total capacity that he prefers to withhold and the portion he allocates to the long-term contracts.

“Simulation output screen”, displayed in Figure 8.11, provides different types of reports summarizing the effects of the selected decisions and parameters on the market, regarding a wide range of aspects, such as the investors’ balance sheet, market share, profit and power plant portfolio, the overall power plant portfolio in the market, the remaining primary energy resources’ reserves, the pool price, the annual peak demand, the electricity reserve margin, long-term contract prices and percentages (regarding total supply). At each pause, the LEMM-user may reevaluate and change his policies and strategies, considering the reports listed above.

On each LEMM-screen the player is free to terminate the game, save the game with a new name, explore between screens via the buttons attached on each screen. On each screen, there are "readme" buttons which provide information to the LEMM-users.

Table 8.1. The ratio of average demand to annual peak demand, in each time interval in the second scenario option for the hourly load curve

Interval	Jan	Feb	Marc	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1st Interval	0.87	0.86	0.82	0.82	0.80	0.81	0.85	0.82	0.80	0.78	0.82	0.85
2nd Interval	0.86	0.82	0.81	0.79	0.77	0.77	0.81	0.80	0.77	0.76	0.81	0.83
3rd Interval	0.93	0.87	0.87	0.84	0.81	0.82	0.86	0.85	0.82	0.81	0.83	0.93
4th Interval	0.96	0.94	0.92	0.91	0.89	0.91	0.95	0.92	0.89	0.87	0.88	0.95
5th Interval	0.95	0.93	0.91	0.90	0.87	0.91	0.95	0.93	0.88	0.87	0.88	0.94
6th Interval	0.95	0.93	0.91	0.88	0.86	0.91	0.94	0.92	0.88	0.86	0.90	0.96
7th Interval	1.00	0.96	0.94	0.87	0.85	0.87	0.91	0.89	0.88	0.89	0.93	0.98
8th Interval	0.97	0.94	0.94	0.92	0.89	0.89	0.93	0.92	0.88	0.88	0.91	0.95
9th Interval	0.94	0.92	0.92	0.90	0.88	0.88	0.91	0.89	0.85	0.86	0.89	0.93

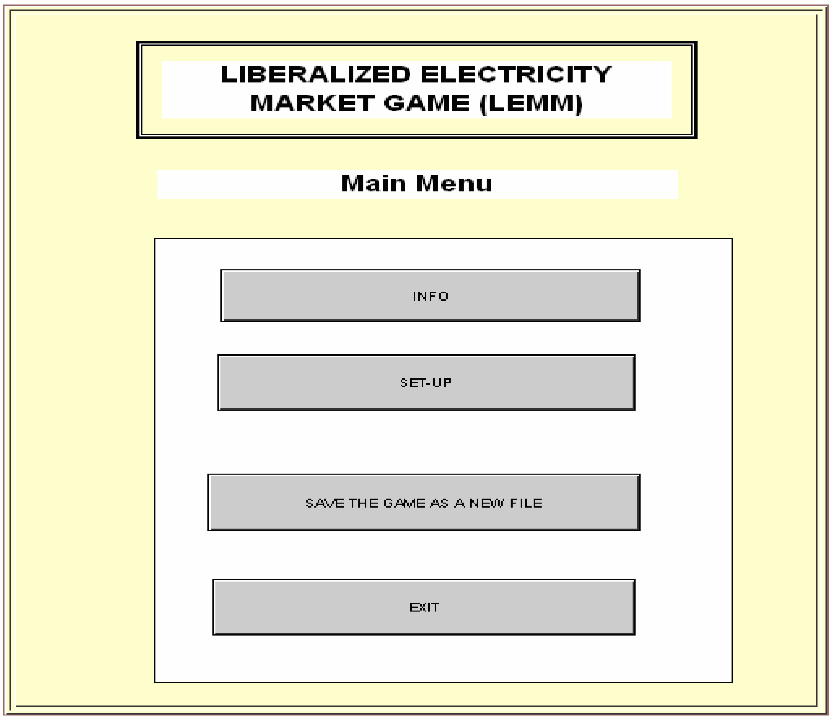


Figure 8.1. The main menu of the LEMM

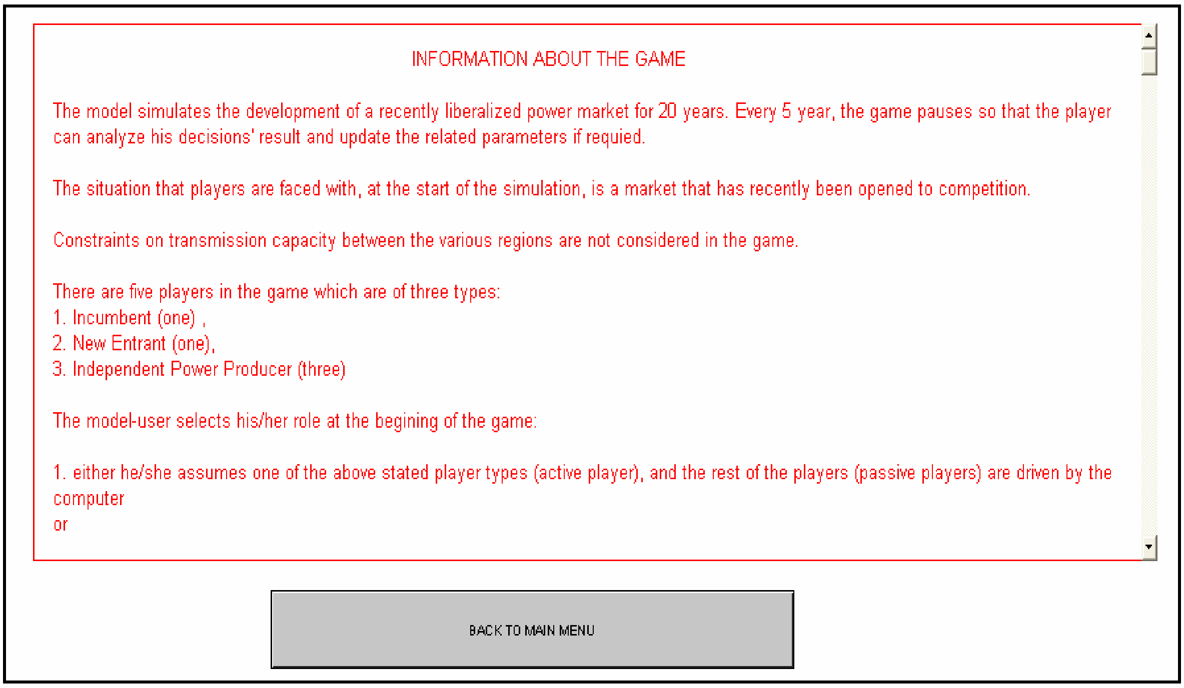


Figure 8.2. The info screen of the LEMM

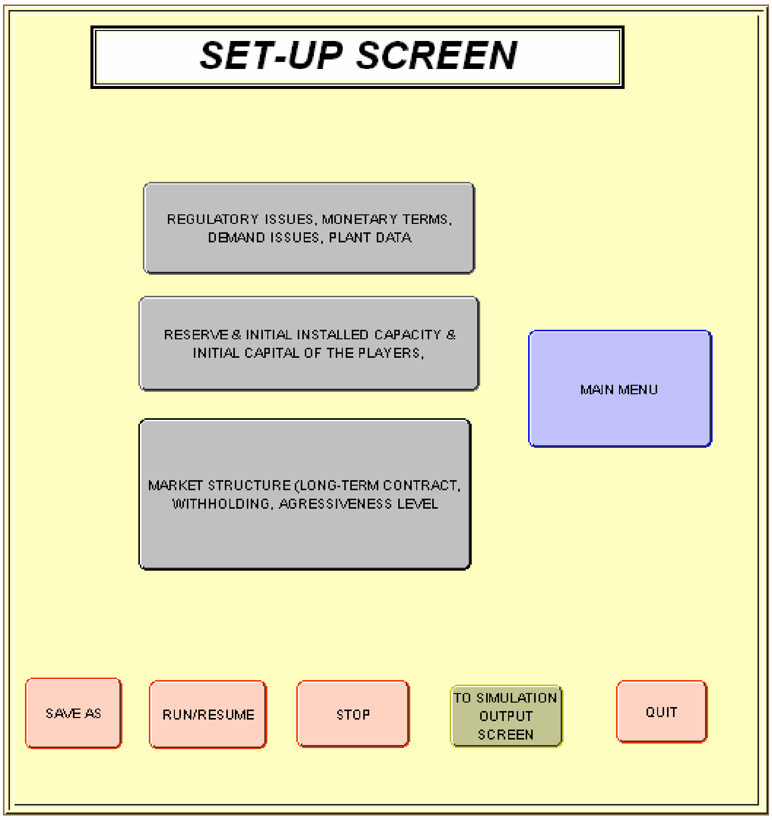


Figure 8.3. The set-up screen of the LEMM

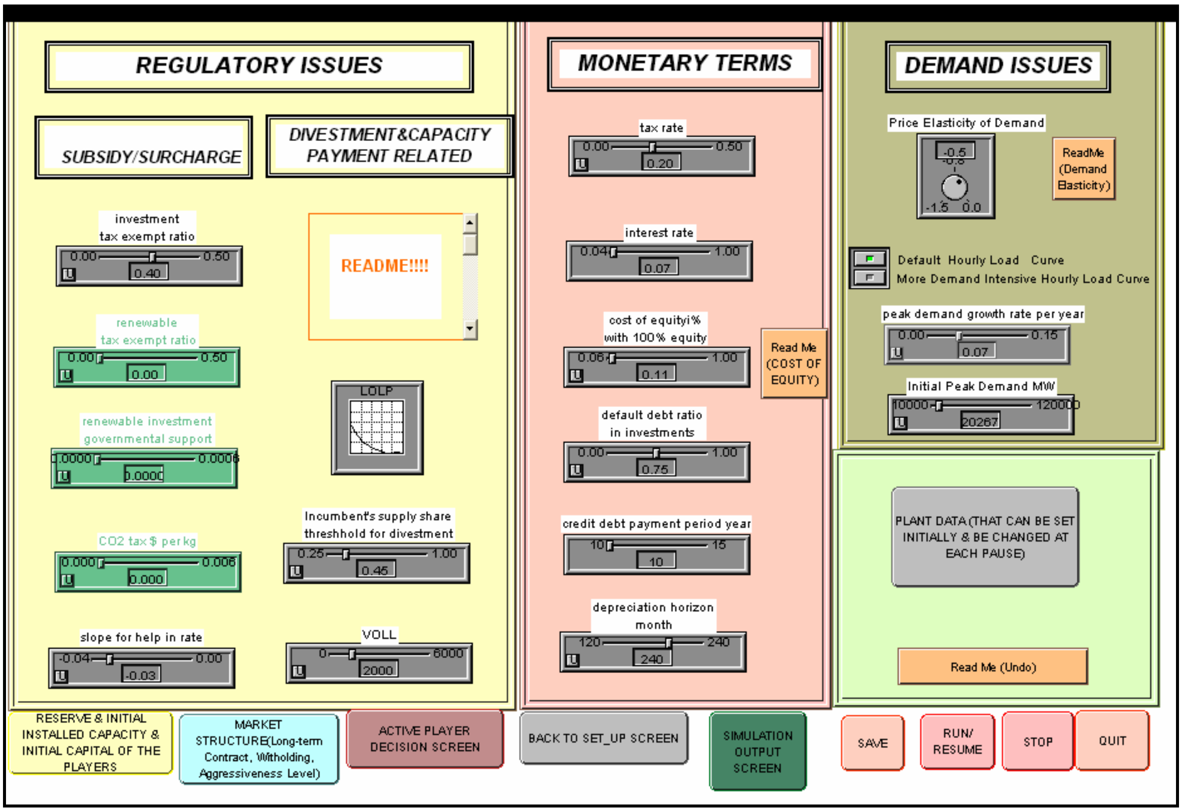


Figure 8.4. The Screen for regulatory issues, financial terms and demand

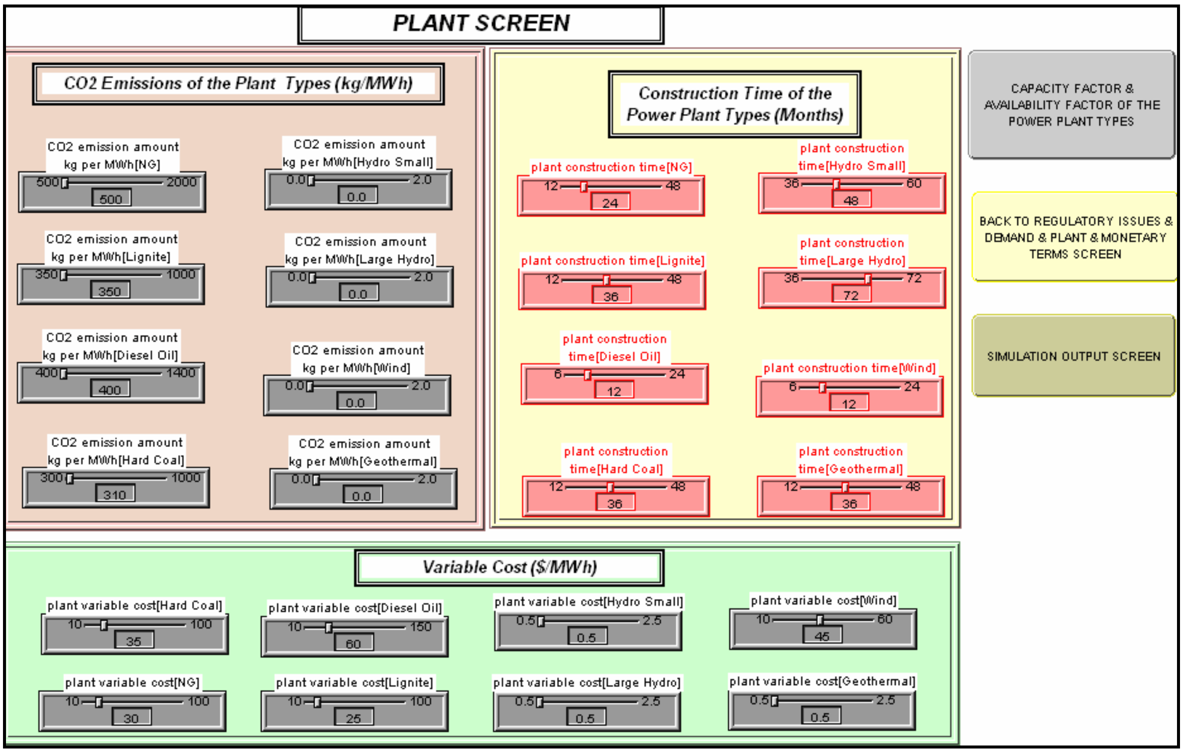


Figure 8.5. The plant screen

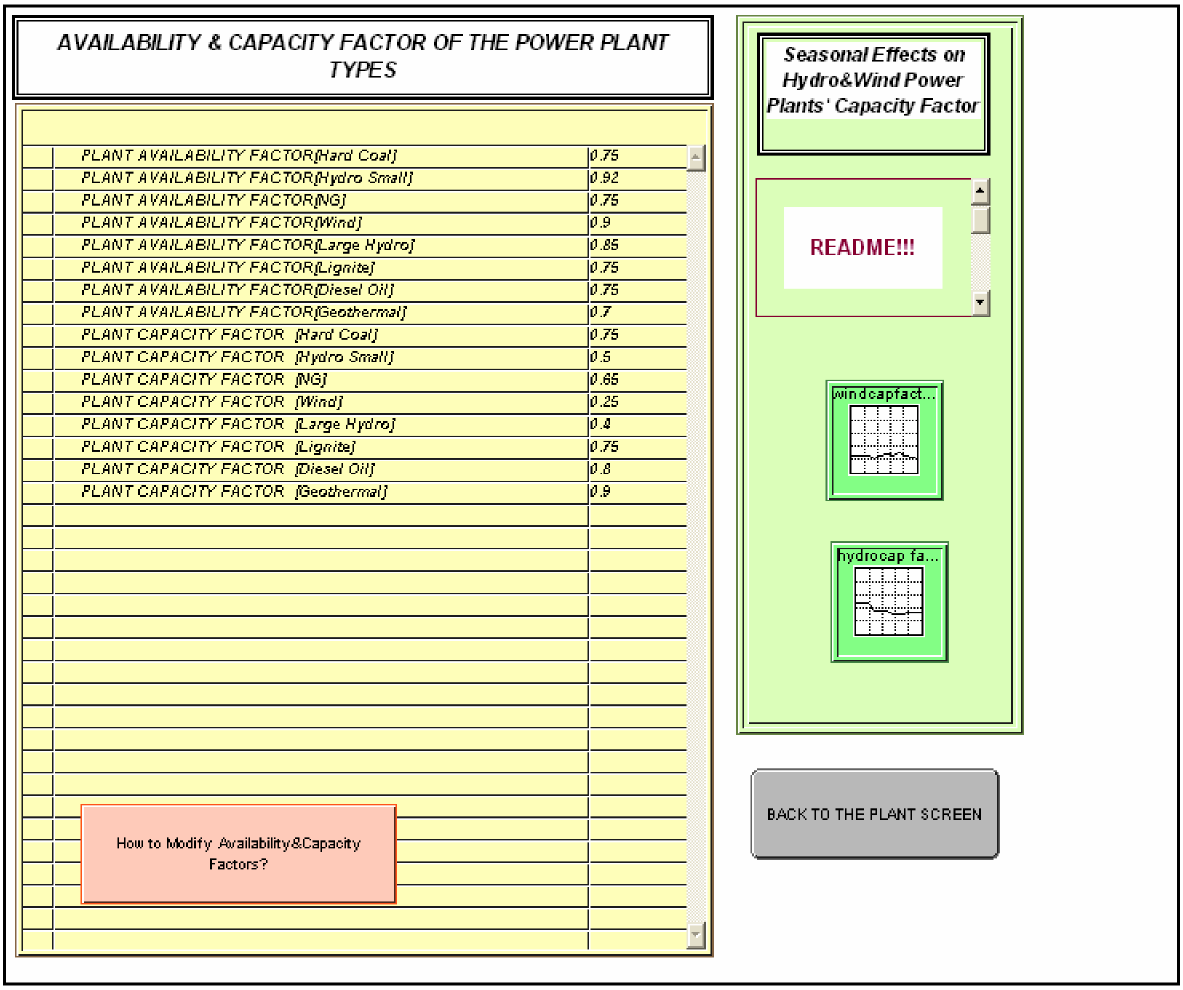


Figure 8.6. The screen for the availability and capacity factors of the power plant types

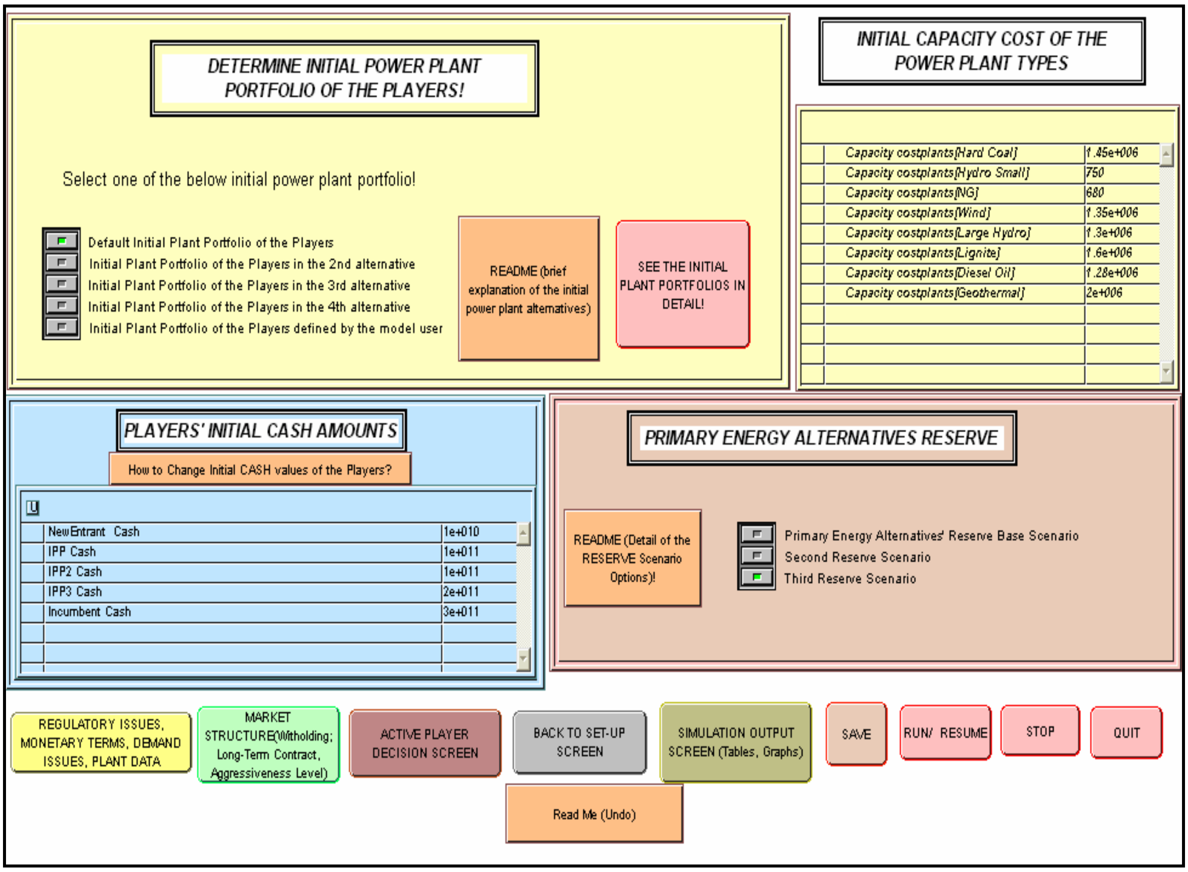


Figure 8.7. The screen for primary energy resources' reserve, initial plant portfolio and capital of investors, and capacity cost of plant types

Initial Power Plant Portfolio of the Players (in the 1st alternative (default setting))

Initial Power Plant Capacity of the Players (MW)

	Incumbent	IPP	IPP2	IPP3	NE	Total
Imported Hard Coal	300	500	-	1210	-	2010
Small Hydro	0	51	-	-	-	51
Natural Gas	6783	4200	3250	5600	-	19833
Wind	-	-	18	-	-	18
Large Hydro	11150	750	880	-	-	12780
Lignite	4747	0	1500	2300	-	8547
Diesel Oil	890	890	900	-	-	2680
Geothermal	23	-	-	-	-	23
Total (MW)	23893	6391	6548	9110	-	45942

Initial Power Plant Portfolio of the Players (in the 2nd alternative)
(Incumbent's major part of the portfolio consists of Large-Hydro&Small Hydro Power Plants,
IPP's major part of the portfolio consists of NG Power Plants,
IPP2's major part of the portfolio consists of Imported-Hard Coal and Lignite Power Plants
IPP3's major part of the portfolio consists of Renewable Power Plants)

Initial Power Plant Capacity of the Players (MW)

	Incumbent	IPP	IPP2	IPP3	NE	Total
Imported Hard Coal	0	0	1000	0	-	1000
Small Hydro	5500	0	-	2000	-	7500
Natural Gas	4000	6000	550	0	-	10550
Wind	-	-	0	000	-	000
Large Hydro	12000	0	0	5000	-	17000
Lignite	1500	400	5000	1000	-	7900
Diesel Oil	890	0	0	-	-	890
Geothermal	23	-	-	300	-	323
Total (MW)	23913	6400	6550.00	9100	-	45963

SEE THE 3rd & 4th INITIAL POWER PLANT PORTFOLIO ALTERNATIVES

RESERVE, INITIAL PLANT PORTFOLIO, CASH AMOUNT OF THE PlAYERS SCREEN

Figure 8.8. The screen for the first two initial plant portfolio options available

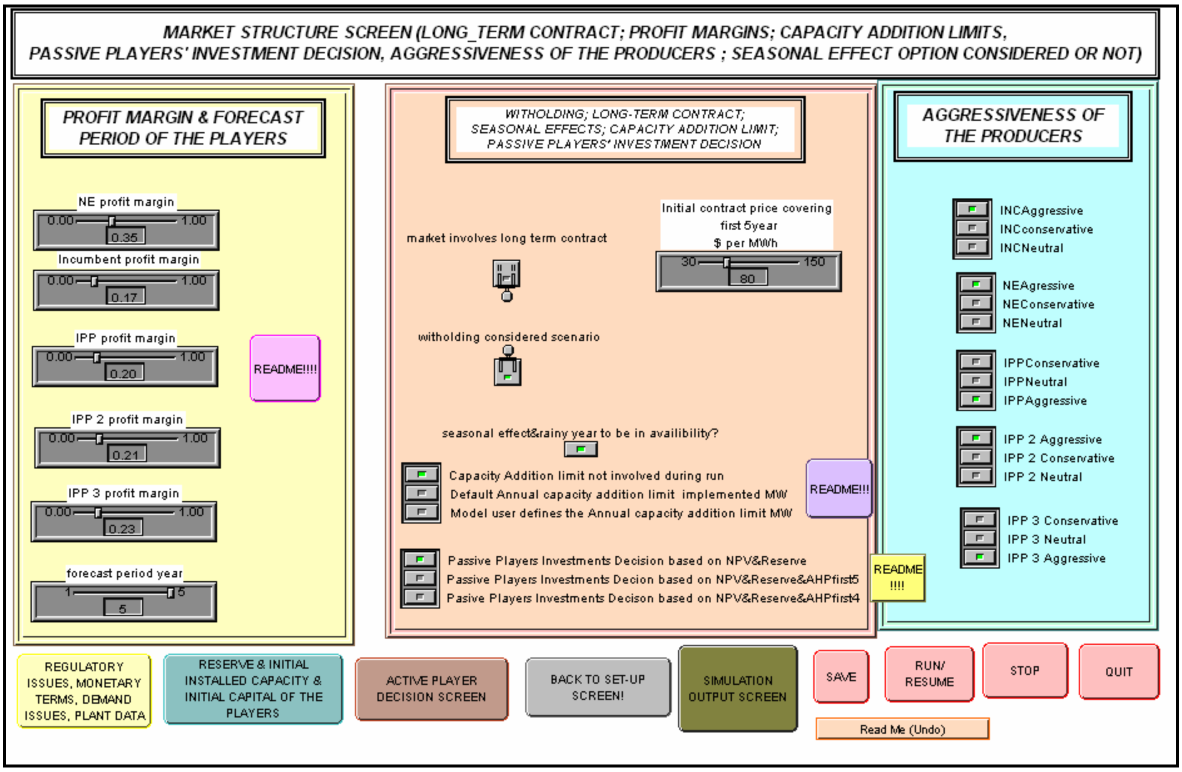


Figure 8.9. The market structure screen

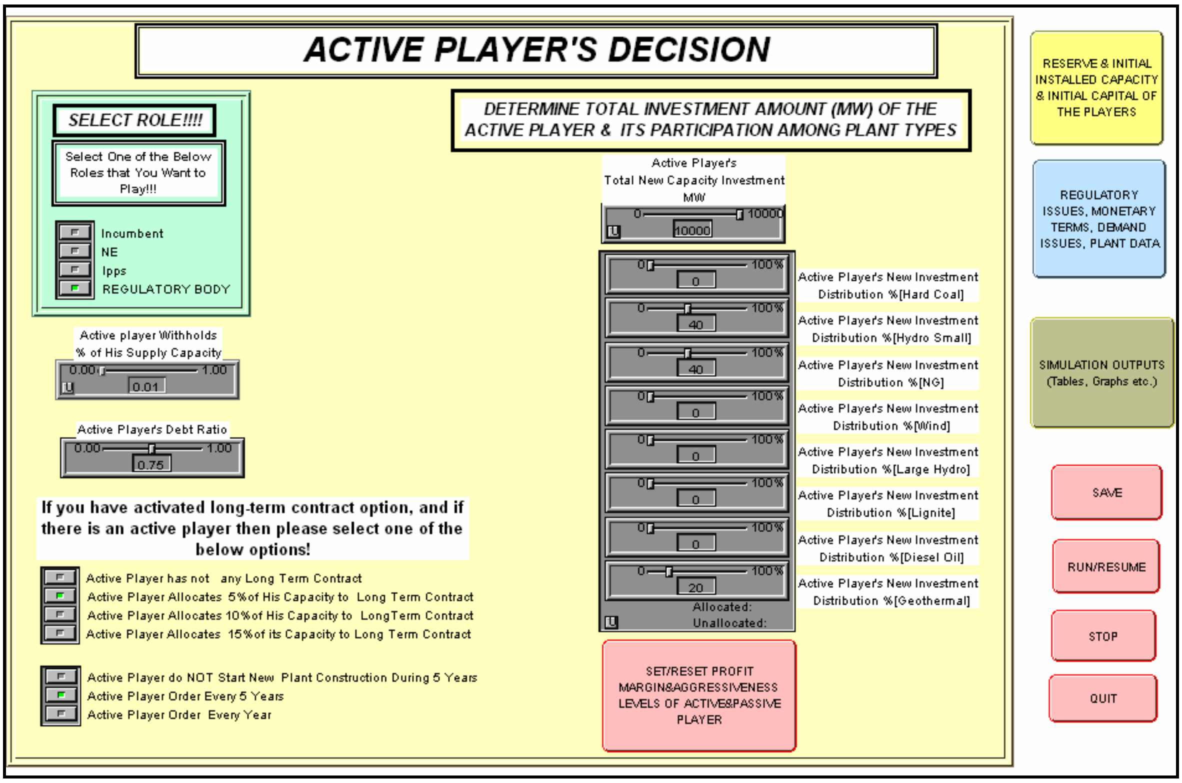


Figure 8.10. The screen for active investor's decisions

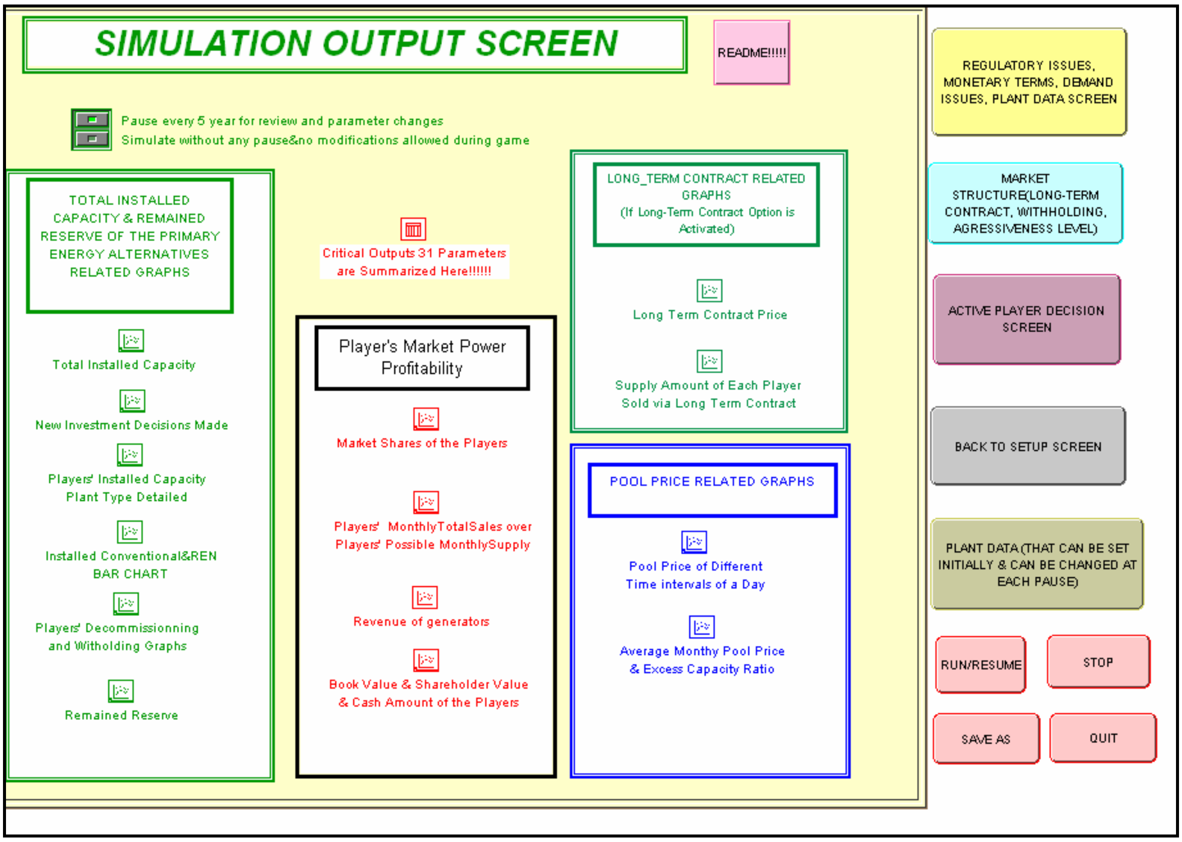


Figure 8.11. The simulation output screen

8.3. Experimentation with the LEMM

As previously mentioned, the LEMM's functionality, practicality, effectiveness and educational capabilities are tested on 26 students of the senior level "Energy Policy and Planning" course at the Sabanci University, in the Spring 2006 semester. These students are split into 13 groups, where five groups played the Regulator role, three the Incumbents role, three the New Entrant's role and the remaining two the IPP's role. It is worth restating that, throughout the experimentation, there was only a single active player during a simulation run (i.e. the remaining players being driven by the computer based on the default decision rules defined in the LEMM)

All of the 13 groups, were informed about the overall game environment, the available options, limitations in the model, the priorities and objectives of the player types and the features of the LEMM's interface, before the start of the experimentation.

8.3.1. Controls Offered to the Regulator to Accomplish His Main Objectives

The Regulator's main objective can be briefly defined as preventing monopolistic practices, encouraging investment in renewable source power plants, promoting competition and avoiding electricity supply gap in the market. If the Regulator role is selected by the active player, then he/she may set/reset any or all of the six decision parameters, listed below, at the beginning of the planning horizon and at the end of every five years, to accomplish the objectives forwarded above.

- The investment tax exemption ratio;
- The renewable tax exemption ratio;
- The state support for renewable energy;
- The VOLL;
- The CO_2 tax;
- The Incumbent's threshold for divestment.

As the detailed explanation of the above parameters are given in Chapter 5, they are not elaborated here. Increasing the first four parameters listed above, provide motivation for making new investments. Accordingly, they are expected to positively influence excess capacity ratio and competition. The second, third and fifth parameters serve to increase the share of renewable energy in total installed capacity. The last parameter directly contributes to the level and balance of competition in the market.

8.3.2. Analysis of the Groups, who Played the Regulator Role

Decisions taken by the five player groups, who played the Regulator role, are presented through Tables 8.2- 8.7.

Table 8.2. Tax exemption ratio deployed by the groups, who selected the regulator role

Player	0-60th Month	61-120 th Month	121-180th Month	181-240th Month
Player 1	0.27	0.30	0.30	0.30
Player 2	0.40	0.40	0.50	0.50
Player 3	0.40	0.30	0.45	0.45
Player 4	0.45	0.40	0.35	0.36
Player 5	0.40	0.35	0.30	0.30

Table 8.3. Renewable tax exemption ratio deployed by the "Regulator" groups

Player	0-60 th Month	61-120th Month	121-180th Month	181-240th Month
Player 1	0.40	0.50	0.50	0.50
Player 2	0.00	0.05	0.05	0.10
Player 3	0.10	0.00	0.15	0.10
Player 4	0.10	0.22	0.20	0.24
Player 5	0.05	0.03	0.10	0.12

Table 8.4. State support for renewable energy (percentage) deployed by the "Regulator" groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 1	0.01	0.01	0.01	0.01
Player 2	0.01	0.01	0.02	0.04
Player 3	0.01	0.01	0.01	0.01
Player 4	0.02	0.04	0.04	0.03
Player 5	0.01	0.00	0.02	0.03

Table 8.5. CO_2 tax ($/kg) deployed by the "Regulator" groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 1	0.002	0.003	0.003	0.003
Player 2	0.001	0.002	0.002	0.002
Player 3	0.001	0.001	0.001	0.003
Player 4	0.040	0.05	0.04	0.04
Player 5	0.001	0.02	0.002	0.002

Table 8.6. Incumbent's threshold for divestment (percentage) deployed by the "Regulator" groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 1	0.34	0.30	0.30	0.30
Player 2	0.50	0.50	0.60	0.60
Player 3	0.45	0.40	0.40	0.40
Player 4	0.35	0.55	0.55	0.49
Player 5	0.45	0.35	0.41	0.40

Table 8.7. VOLL ($/MWh) deployed by the "Regulator" groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 1	2600	2400	2400	2400
Player 2	2000	2500	2500	3000
Player 3	2000	2000	2000	2000
Player 4	2000	3000	3000	2200
Player 5	1800	2200	2100	2200

8.3.3. Performances of the Active Players, who Played the Regulator Role

The performance of the players who assumed the Regulator role is evaluated in terms of the excess capacity ratio, the total installed renewable power plant, the competition in the market, the average monthly pool price and the overall power plant portfolio in the market. Throughout Sections 8.3.3.1-8.3.3.5, the performances of these groups are discussed with respect to the performance measures forwarded above. It should be noted that, for the sake of briefness, in the figures throughout Section 8.3, only the values, obtained at the end of the five years period, are illustrated. Besides, since IPP1, IPP2 and IPP3 have similar characteristics, throughout Section 8.3, only IPP1 is depicted as a representative of the IPPs.

8.3.3.1.<u>The Excess Capacity Ratio</u>: As explained in Equation 5.6, the excess capacity ratio defines the excess supply in the market based on the peak demand. As price inelastic demand is assumed throughout the experiments, it is quite rational to compare the performance of the players, who have selected the Regulator role, based on their excess capacity ratio performance.

Figure 8.12 presents the excess capacity ratios obtained by the said five groups. Considering the results obtained at the end of the 240th month, the performance of the first and second players have been distinctively well and in line with expectations: the first player offered high VOLL, high tax exemption ratio for all plant types and additional tax exemption for renewable energy and the second player offered high VOLL and the highest tax exemption ratio. On the other hand, the third player performed the worst (probably because he offered the lowest average VOLL).

Additionally, Figure 8.12 indicates that all five groups ended up with an electricity shortage. The shortage observed by the end of the planning horizon is more than 15 per cent in all cases. The major reasons for the electricity shortage in the market are as follows;

- Initial total installed and under construction capacity are not sufficient for meeting the electricity demand of two years into the future (especially during the peak hours)
- Since price-inelastic electricity demand is assumed in all cases, demand increases continuously. However, the increase in the total installed capacity is comparatively lower than the growth in the electricity demand.

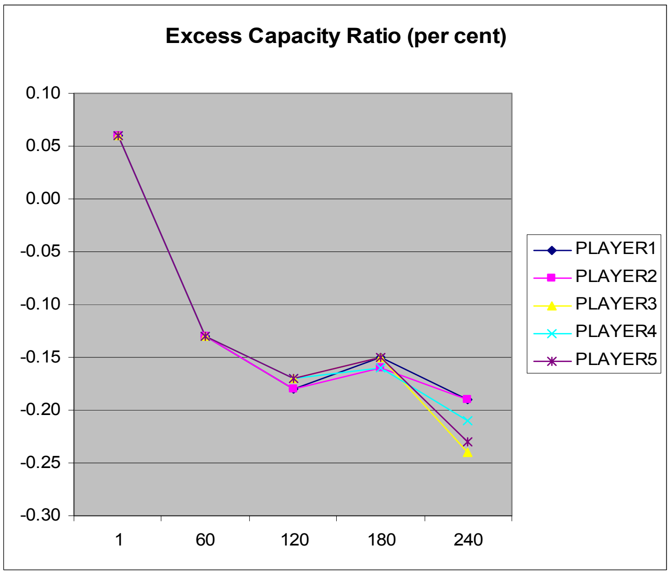


Figure 8.12. Excess capacity ratio performance of the “Regulator” groups

8.3.3.2. <u>The Total Installed Renewable Plant Capacity</u>: Figure 8.13 illustrates the total installed renewable power plant capacity performance of the five players, who selected the Regulator role. Comparison of the groups with respect to the values attained by this performance measure, at the end of 240 months, reveal that the first and the second groups have out performed the others. This is again in line with expectations: These players offered high VOLL and high tax exemption ratios, while the second group offered a considerable amount of additional tax exemption ratio for renewables, as well. The performance of the forth group, who selected the highest CO_2 tax, follows the first and second group. On the other hand, the third group, who has the lowest average VOLL over the planning horizon, has the worst performance.

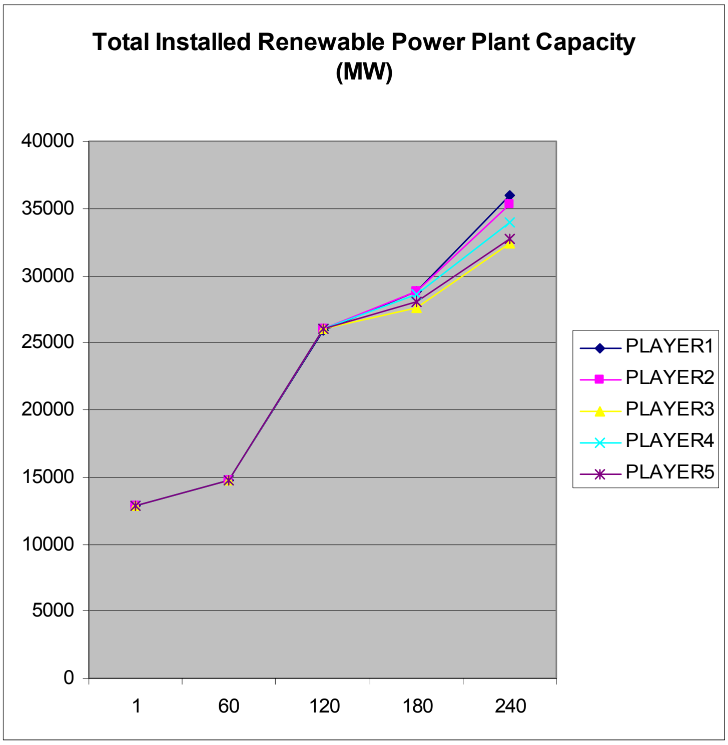


Figure 8.13. Total installed renewable plant capacity performance of the “Regulator” groups

8.3.3.3. <u>The Competition in the Market:</u> The effect of the Regulator’s decisions on the competition in electricity market is evaluated by comparing the market shares of the Incumbent, and the NE at five year intervals. (Since market share of the Incumbent represents monopolistic behavior, whereas market share of the New Entrant indicates higher competitiveness in the market).

The Incumbent market share attained by the second group has been higher than that of the others, as observed in Figure 8.14. This is in line with the observation that the second group selected the highest threshold level for divestment (as can be seen in Table 8.6.)

The first group, on the contrary, selected the lowest threshold level for divestment. As a consequence, in the first group's trial the Incumbent's monopolistic power (market share) decreased earlier than that of the cases for the other four groups.

As a consequence of divestments and various incentives offered to the investors, the Incumbent's market share gradually decreases throughout the planning horizon, in all cases. As can be seen in Figure 8.14, the Incumbent's market share is around 30 per cent (in all cases) by the end of the planning horizon.

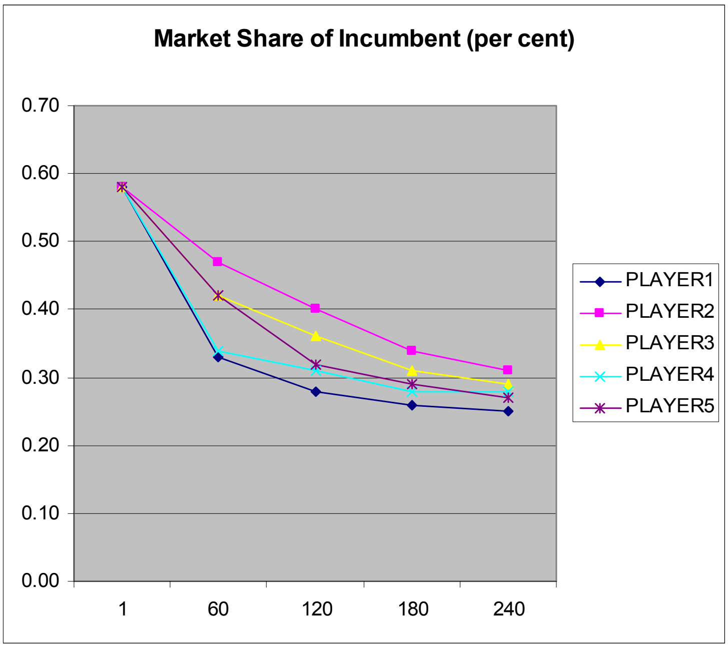


Figure 8.14. The Incumbent market share performance of the "Regulator" groups

Figure 8.15. presents the NE's market share in the trials of the five Regulator groups. In all cases, the NE has a market share less than 11 per cent, at the end of the planning horizon. The policy of the first group seems to support the NE entry the most, whereas the policy of the second group seems to support it the least. It is worthwhile to note here that the NE's market share increases, as the threshold level for divestment decreases.

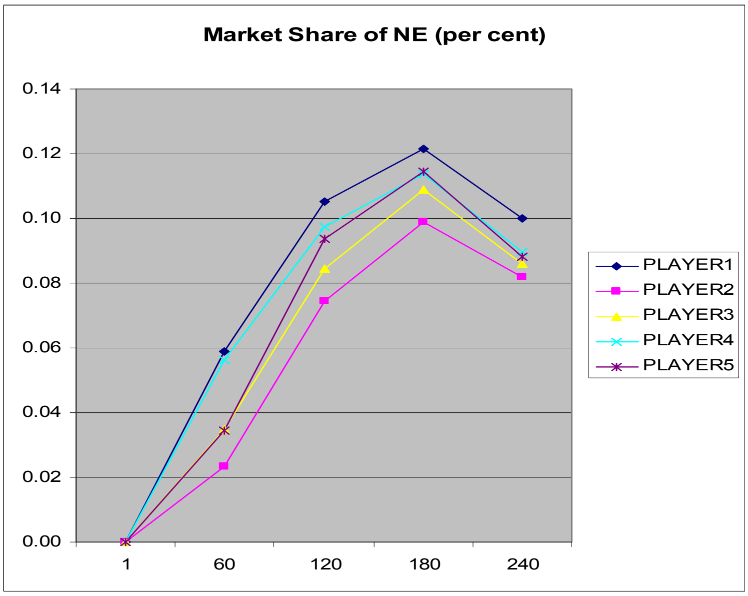


Figure 8.15. The NE market share performance of the "Regulator" groups

8.3.3.4. <u>The Average Monthly Pool Price</u>: As presented in Figure 8.16, the average monthly pool prices take its lowest value in the first group's trial, (since excess capacity ratio takes its highest value in this trial). Similarly, the average monthly pool prices take its highest value in the fifth and third groups' trials, since excess capacity ratio take its lowest values in these trials.

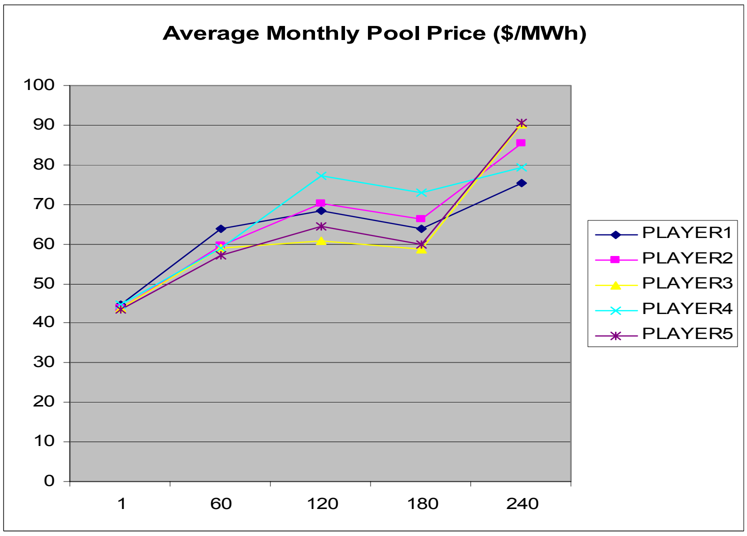


Figure 8.16. The average monthly pool price performance of the "Regulator" groups

8.3.3.5. <u>The Power Plant Portfolio in the Market</u>: The five groups' actions did not lead to significant differences regarding the overall plant portfolio in the market:

i. In all of the five cases, the country's small hydro potential is fully utilized within the first half of the planning horizon, owing to low investment and unit production costs of these plants.

ii. Although all of the five groups offer incentives for renewable energy, no wind plants are installed in the five cases, due to high investment and unit production costs of these plants.

iii. In all of the five cases, the country's national gas potential is fully utilized by the end of the planning horizon, owing to low investment costs of these plants.

However, as presented in Figure 8.17, at the end of the planning horizon, total installed large hydro plant capacity in the first group's trial is higher than that of the case in the other groups' trials, (since the first group offered the highest extra tax exemption ratio for promoting renewable energy.) On the other hand, the lowest total installed large hydro-power plant capacity takes place in the trials of the third and the fifth groups, who offered the lowest VOLL.

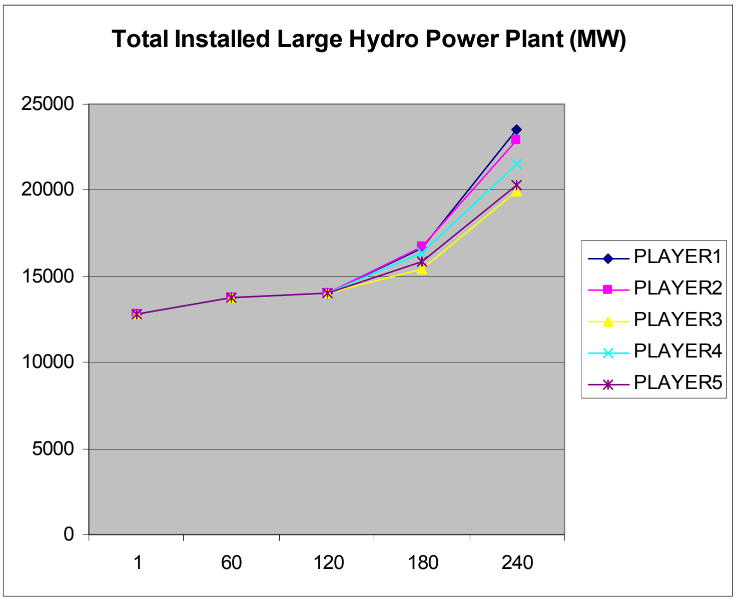


Figure 8.17. Total installed large-hydro plant capacity performance of the "Regulator" groups

8.3.4. Controls Offered to the Active Investor to Accomplish His Main Objectives

The investors main objective can be briefly defined as making profit and keeping/increasing their market shares. If one of the investor types' (INC, NE or IPPs) role is selected by the active player, then he/she may set/reset any or all of the seven decision parameters, listed below, at the beginning of the planning horizon and every five years to accomplish the objectives forwarded above.

- Profit margin
- Aggression level (aggressive, conservative or neutral)
- Witholded portion of the active player's capacity
- Debt ratio in new investment
- Frequency of the new investment decision (invest as much as the inputted investment amount every year during the next 5 years periods, invest as much as the inputted investment amount only at the beginning of the next 5 years periods, do not make any investment during the next five years period)
- Total investment amount
- Distribution of the total investment amount to the power plant types.

Since the LEMM provides decision support to the active player with various reports, which comprehensively reflect the behavior and conditions of the market, decisions of the active player is totally up to himself; no feasibility check, in terms of profitability, is applied on such decisions. The decisions of the active player is however, checked regarding the affordability of the investment in terms of potential cash flow requirements and country's primary energy resources' reserves. If the investment can not be completely realized due to cash flow requirements or primary energy resources' reserves limitations, it is automatically partially undertaken (as much as it can be afforded by the player and the country's remaining primary energy resources' reserve level).

As explained previously, three out of 13 player groups selected the Incumbent role, three the New Entrant role, and two the IPP role. In Figures 8.18-8.33, Players 6, 7, and 8 denote the player groups who have selected the Incumbent's role, Players 9, 10 and 11 denote the player groups who have selected the NE's role, Players 12 and 13 denote the player groups who have selected the IPP1's role.

8.3.5. The Performance Measures Used for the Active Players, who Played One of the Investor Roles

The primary objective of all investor types is to make profit, whereas the secondary objective of the investors is to keep/increase their market shares. Therefore, if a player group selects one of the investor types' (NE, INC, IPP) role, their performance is compared with the other player groups, who selected the same role, with respect to their total profit and market shares. Additionally, average monthly pool prices, total installed capacity and excess capacity ratio are also considered for describing the market behavior resulting from the actions of the player (and, as such being additional performance measures).

8.3.6. Analysis of the Groups, who Played the Incumbent Role

Decisions taken by three player groups, who played the Incumbent role, are presented through Table 8.8-Table 8.19. As explained in Section 8.3.4, the active players, may set/reset seven parameters at the beginning of the planning horizon and then at every five years.

Table 8.8. Profit margins of the Incumbent groups (percentage)

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	0.40	0.45	0.35	0.45
Player 7	0.11	0.17	0.19	0.19
Player 8	0.40	0.45	0.60	0.23

Table 8.9. Withheld capacities of the Incumbent groups (percentage)

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	0.11	0.15	0.15	0.09
Player 7	0.01	0.04	0.09	0.13
Player 8	0.36	0.45	0.25	0.31

Table 8.10. Debt ratios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	0.80	0.71	1.00	0.72
Player 7	0.72	0.72	0.69	0.75
Player 8	0.37	0.37	0.20	0.17

Table 8.11. Total investment amounts (MW) of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	10000	10000	10000	7500
Player 7	10000	10000	10000	10000
Player 8	8000	9100	8700	10000

Table 8.12. Percentage of imported hard coal plant investments in portfolios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	0	0	0	17
Player 7	0	0	0	8
Player 8	0	0	0	0

Table 8.13. Percentage of small-hydro plant investments in portfolios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	0	0	0	0
Player 7	40	36	29	23
Player 8	0	0	0	31

Table 8.14. Percentage of natural gas plant investments in portfolios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	50	71	9	0
Player 7	40	36	29	23
Player 8	0	0	0	0

Table 8.15. Percentage of wind plant investments in portfolios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	0	0	0	0
Player 7	0	12	16	11
Player 8	63	45	31	12

Table 8.16. Percentage of large-hydro plant investments in portfolios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	25	19	19	0
Player 7	0	0	18	14
Player 8	0	0	0	20

Table 8.17. Percentage of lignite plant investments in portfolios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	0	0	0	83
Player 7	0	0	0	7
Player 8	0	25	7	0

Table 8.18. Percentage of diesel-oil plant investments in portfolios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	25	10	68	0
Player 7	0	0	0	12
Player 8	0	0	56	37

Table 8.19. Percentage of geothermal plant investments in portfolios of the Incumbent groups

Player	0-60th Month	61-120th Month	121-180th Month	181-240th Month
Player 6	0	0	4	0
Player 7	20	16	8	2
Player 8	37	30	6	0

As illustrated in Table 8.8, Player 7 inputted the lowest profit margin, while. Player 6 and Player 7 adopted aggressive behavior throughout the entire planning horizon. Player 8 preferred to be conservative in the third quarter of the planning horizon and aggressive in the rest of the trial. In other words, general tendency of the players, playing the Incumbent role, has been to act as aggressive investors.

Table 8.9 indicates that all of the players, who selected the Incumbent role, withheld a portion of their capacities throughout the entire planning horizon. Besides, Player 7 had the highest and Player 8 had the lowest withholding ratio.

Table 8.10 illustrates that Player 6 and Player 7 preferred to borrow more than 70 per cent of their investment costs, whereas Player 8 preferred to have significantly lower debt ratio.

Player 6 and Player 7 planned to expand their capacity faster as the amounts presented in Table 8.11, whereas Player 8 planned a slower expansion up to the last quarter of the planning horizon.

Plant type preferences of the players, who selected Incumbent role, are illustrated through Table 8.12-Table 8.19. In general, preferences of Player 6 and Player 7 are similar and somewhat different from that of Player 8.

In the first three quarters of the planning horizon, Player 6 made 20 per cent of his new investments in large hydro-power plants and the remaining 80 per cent in diesel-oil and natural gas power plants. In the last quarter, though, his preferences shifted completely to lignite and imported-hard coal plants.

Investment decisions of Player 7 are parallel to the preliminary and secondary scenario analysis findings given in Chapter 7. The investment decision of Player 7 is summarized below;

- Investing in small hydro-power plants as long as its resource is available.
- Investing in large hydro-power plants once reserves for small- hydro power plants are fully utilized.
- Investing in natural gas power plants throughout the planning horizon.
- Prefering lignite, imported hard-coal and diesel-oil power plants towards the end of the planning horizon (since average monthly pool prices are high enough to invest in these power plant types, at this time).
- Investing in geothermal power plant throughout the entire planning horizon.
- The major difference between the behavior of Player 7 and that of the passive players is the wind plants. Player 7 insisted on investing in wind plants and allocated around 12 per cent of his investments in wind plants, throughout the last three quarters of the planning horizon.

Investment preferences of Player 8 are different from those of the Player 6 and Player 7. Whereas Player 6 did not invest in wind power plants and Player 7 allocated around 12 per cent of his investments to wind power plants, Player 8 allocated major part of his investments to wind power plants. Contrary to Player 6 and Player 7, Player 8 did not invest in any natural gas and small hydro-power plants during the first three quarter of the planning horizon. However, Player 8 wanted to invest in small hydro-power plants in the last quarter of the planning horizon, but could not realize it, because all of the country's small-hydro potential had already been utilized by then.

8.3.7. Performances of the Active Players, who Played the Incumbent Role

In this section first, the effects of the players' decisions on the market are presented. Then, the effects of the players' decisions on the players' wellbeing (with respect to their cumulative profit and their market shares) are presented.

8.3.7.1. Effects of the decisions of active players on the market: It is observed that the effcts of different players (who played the Incumbent role) on the market have been quite varied. The main differences and causes of these differences are explained below.

As displayed in Table 8.9, Player 8 withheld a larger portion of his capacity than Players 6 and 7 did. As a consequence, as illustrated in Figure 8.18, excess capacity ratio observed in Player 8's trial remained lower than those of the cases of Player 6 and Player 7.

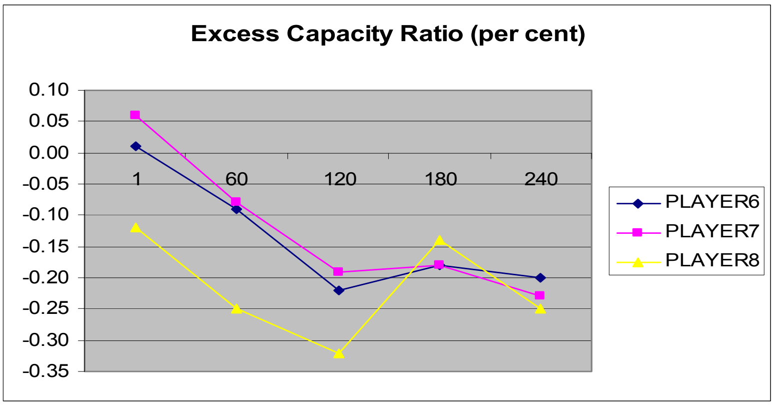


Figure 8.18. Excess capacity ratios observed in the trials of the groups, who selected the Incumbent role

Parallel to the excess capacity ratio, average monthly pool price has been higher in Player 8's trial than that of the case for Player 6 and Player 7, (as illustrated in Figure 8.19).

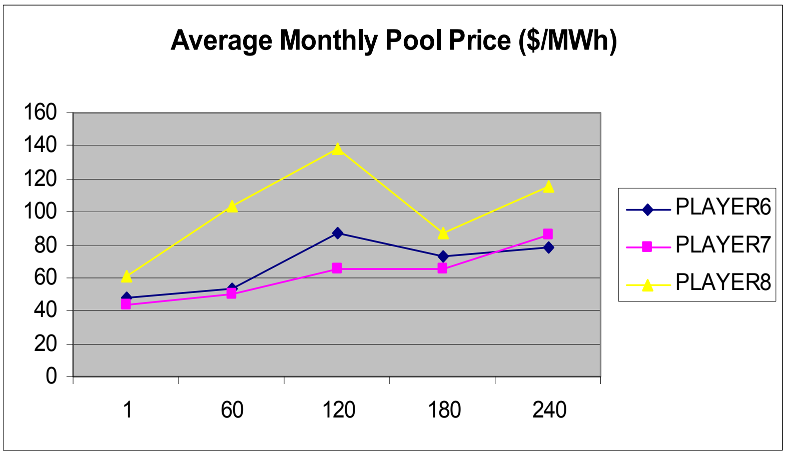


Figure 8.19. The average monthly pool prices observed in the trials of the groups, who selected the Incumbent role

As explained in Chapter 7, pool price directly affects investment decision of the players. The higher pool price, that occurred in the trial of Player 8, motivated passive players for new investments which in turn caused a distinctly higher total installed capacity in this trial, as compared to the total installed capacity in the trials of Player 6 and Player 7. (Figure 8.20).

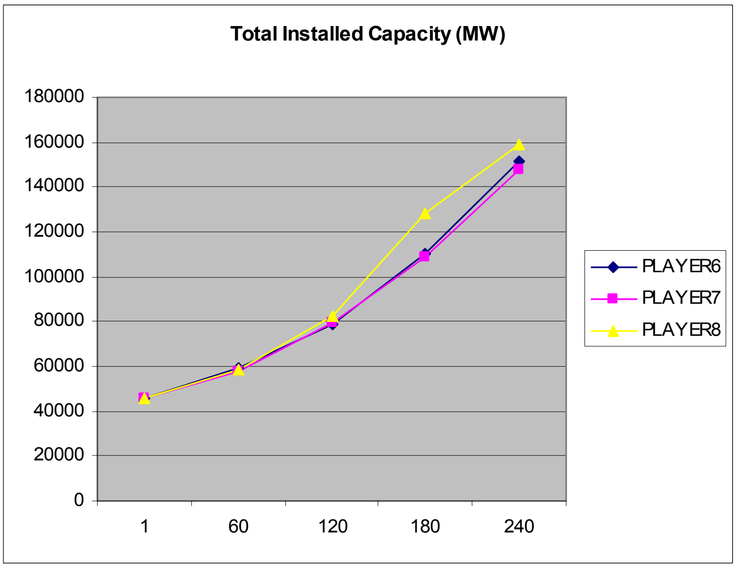


Figure 8.20. The total installed capacity in the trials of the groups, who selected the Incumbent role

8.3.7.2. Effects of the decisions of active players, on their own well-being: As can be seen in Figure 8.21, Player 8's market share is lower than market shares of Player 6 and Player 7, within the first half of the planning horizon. The main reason for this is that the Player 8 withheld a comparatively higher portion of his available supply in comparison to the Players 6 and 7 did. On the other hand, the market share of Player 8 is higher than that of Players 6 and 7, in the second half of the planning horizon. The reasons for this outcome are explained below.

As presented in Table 8.13 and Table 8.16, Player 8 did not invest in hydro-power plants in the first three quarters of the planning horizon. As a consequence, most new investments of Player 8 became operational within the second half of the planning horizon, whereas new hydro-power plants of the Players 6 and 7 were still under construction. As a result, although Player 8 withheld a larger portion of his available supply, his market share is higher, as his total installed capacity is higher than total installed capacity of Player 6 and 7.

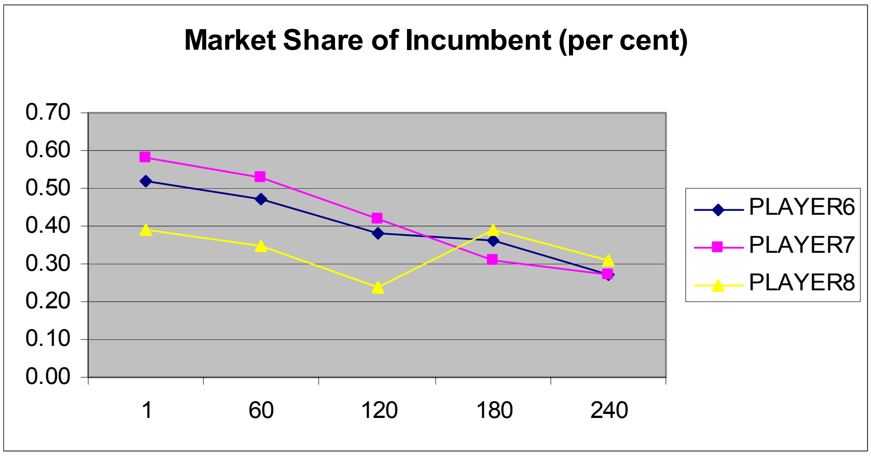


Figure 8.21. The market share of the active players, who selected the Incumbent role

Figure 8.22 presents total profits of the active players, who selected the Incumbent role. As can be observed from Figure 8.22, Player 8 acquired higher profits as compared to Players 6 and 7, since Player 8 withheld a larger portion of his available supply and thereby effected a much higher average monthly pool price in the market than the cases of Players 6 and 7.

Player 7 made the second highest profit. The main reason why Player 7 made more profit than Player 6 is that Player 7 invested in power plant types with comparatively lower unit production cost, (such as small hydro and geothermal plants), whereas Player 6 invested in diesel-oil plants which have the highest unit production costs.

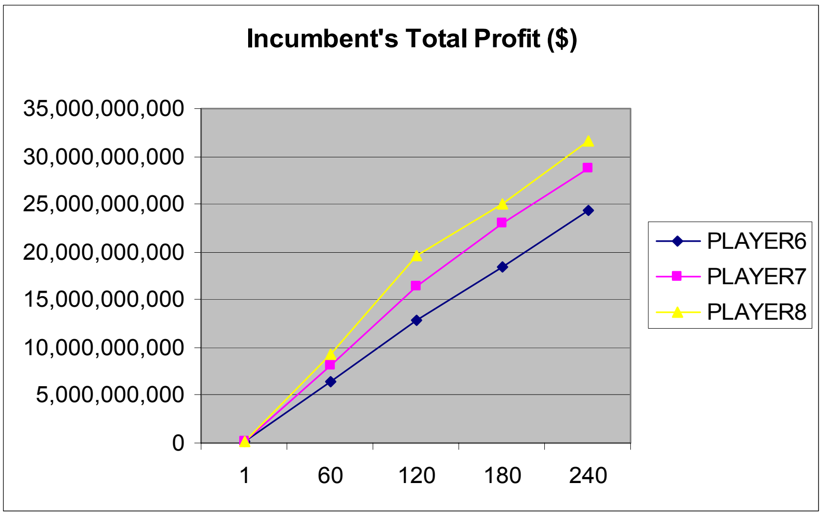


Figure 8.22. Total profit of the active players, who selected the Incumbent role

8.3.8. Experiments of the Players, who Played the New Entrant Role

As explained previously, Player 9, Player 10 and Player 11 selected the NE role. The decisions taken by these players are presented in Tables 8.20- 8.31. Unfortunately, Players 9, 10 and 11 went bankrupt within the second quarter, the third quarter and the first quarter respectively of the planning horizon. Thus, their trials end within the planning horizon, thereby leading to the empty cells in Tables 8.20-8.31.

Table 8.20. Profit margins of the NE groups

	0-60 th Month	**61-120 th Month**	**121-180 th Month**	**181240 th Month**
Player 9	0.20	0.20	-	-
Player 10	0.67	0.67	0.81	-
Player 11	0.19	-	-	-

Table 8.21. Withheld portion of the capacities of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	0.07	0.07	-	-
Player 10	0.75	0.75	0.01	-
Player 11	0.07	-	-	-

Table 8.22. Debt ratios of the NE groups in new investments

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	0.09	0.09	-	-
Player 10	0.40	0.44	0.61	-
Player 11	0.75	-	-	-

Table 8.23. Total investment amount (MW) of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	5900	2700	-	-
Player 10	10000	10000	10000	-
Player 11	5100	-	-	-

Table 8.24. Percentage of imported hard coal plants in portfolios of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	42	0	-	-
Player 10	75	75	34	-
Player 11	1	-	-	-

Table 8.25. Percentage of small-hydro plants in portfolios of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	0	32	-	-
Player 10	25	25	22	-
Player 11	12	-	-	-

Table 8.26. Percentage of natural gas plants in portfolios of the NE groups

	0-60 th Month	61-120 th Month	120-180 th Month	180-240 th Month
Player 9	13	21	-	-
Player 10	0	0	22	-
Player 11	8	-	-	-

Table 8.27. Percentage of wind plants in portfolios of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	0	12	-	-
Player 10	0	0	0	-
Player 11	30	-	-	-

Table 8.28. Percentage of large-hydro plants in portfolios of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	0	17	-	-
Player 10	0	0	21	-
Player 11	4	-	-	-

Table 8.29. Percentage of lignite plants in portfolios of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	22	0	-	-
Player 10	0	0	0	-
Player 11	13	-	-	-

Table 8.30. Percentage of diesel-oil plants in portfolios of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	23	0	-	-
Player 10	0	0	0	-
Player 11	16	-	-	-

Table 8.31. Percentage of geothermal plants in portfolios of the NE groups

	0-60 th Month	61-120 th Month	121-180 th Month	181-240 th Month
Player 9	0	18	-	-
Player 10	0	0	1	-
Player 11	16	-	-	-

As a consequence of the reasons cited below, Player 9 ran out of funds to cover his operational and interest costs and finally went bankrupt, in line with expectations.

i. Within the first quarter of the planning horizon, Player 9 allocated a major portion of his investment (87 per cent) to imported hard-coal, lignite and diesel oil plants, which have comparatively higher investment and unit production costs.
ii. Player 9 preferred to meet a major part (91 per cent) of his new investment by using his liquid assets, although his liquid assets were quite limited.
iii. Player 9 set a very low profit margin.

Since Player 10 could cover his costs throughout the earlier phases of the planning horizon (due to his high profit margin), he survived in the market longer than Player 9 and Player 11 did. However, in line with expectations, Player 10 went bankrupt, as he planned a considerably large amount of capacity expansion with respect to his low financial power.

Since Player 11 invested in wind, large-hydro, lignite, diesel-oil and geothermal plants, (all having high investment costs) within the first quarter of the planning horizon, and he set a low profit margin, he went bankrupt in line with expectations.

The major reason why all players who selected the NE role, went bankrupt, is their preference of attempting to increase their total installed capacity as soon as possible (a short sighted and greedy short term profitability drive). The NE have no power plants and very limited financial potential at the beginning. Therefore, the NE should behave conservatively at the beginning of the planning horizon and try to cover investment costs, (instead of attempting to increase total installed capacity in the short-term) in order to survive throughout the rest of the planning horizon. However, all of the three players, who selected the NE role, have ignored this prudence and consequently they went bankrupt.

8.3.9. Decisions Taken by the Active Players, who Played IPP Role

As explained previously, Player 12 and Player 13 selected the IPP role. The decisions of Player 12 and Player 13 are presented through Table 8.32-Table 8.43.

Player 13's profit margin and the ratio of his withheld capacity to his available capacity are higher than the related values set by Player 12, as observed in Tables 8.32 and 8.33. As illustrated in Table 8.34, Player 12 preferred debt financing more than Player 13 did.

Tables 8.36-8.43, which present investment decision of Players 12 and 13, reveals the following issues:

- Player 12 increased his capacity more than Player 13 did.
- Player 12's portfolio included more renewable power plants (hydro and wind plants) than the portfolio of Player 13.

- Both players preferred small hydro, wind, diesel oil and geothermal plants more than other plant types throughout the entire planning horizon.
- Although players planned to construct new small-hydro power plants throughout the entire planning horizon, they could not make any further small hydro-power plant investment after the first half of the planning horizon, since the country's resource reserve for small hydro plants has already been utilized by the 120th month.
- Both players intended to make more investments in geothermal plants, but could not do so, due to the country's limited resource reserves.

Table 8.32. Profit margins of the IPP groups

	0-60 th Month	**61-120 th Month**	**120-180 th Month**	**180-240 th Month**
Player 12	0.20	0.29	0.29	0.47
Player 13	0.40	0.40	0.35	0.75

Table 8.33. Withheld portions of the capacities of the IPP groups

	0-60 th Month	**61-120 th Month**	**120-180 th Month**	**180-240 th Month**
Player 12	0.09	0.09	0.09	0.09
Player 13	0.09	0.15	0.28	0.20

Table 8.34. Debt ratios of the IPP groups

	0-60 th Month	**61-120 th Month**	**120-180 th Month**	**180-240 th Month**
Player 12	0.75	0.75	0.75	0.75
Player 13	0.55	0.47	0.43	0.80

Table 8.35. Total investment amounts (MW) of the IPP groups

	0-60 th Month	**61-120 th Month**	**120-180 th Month**	**180-240 th Month**
Player 12	8700	8700	10000	10000
Player 13	7500	6500	6000	8000

Table 8.36. Percentage of imported-hard coal plants in portfolios of the IPP groups

	0-60 th Month	**61-120 th Month**	**120-180 th Month**	**180-240 th Month**
Player 12	0	0	0	0
Player 13	20	17	33	24

Table 8.37. Percentage of small-hydro plants in portfolios of the IPP groups

	0-60 th Month	61-120 th Month	120-180 th Month	180-240 th Month
Player 12	31	31	29	22
Player 13	15	12	9	35

Table 8.38. Percentage of natural gas plants in portfolios of the IPP groups

	0-60 th Month	61-120 th Month	120-180 th Month	180-240 th Month
Player 12	7	7	6	0
Player 13	11	9	6	2

Table 8.39. Percentage of wind plants in portfolios of the IPP groups

	0-60 th Month	61-120 th Month	120-180 th Month	180-240 th Month
Player 12	31	31	43	37
Player 13	9	31	29	26

Table 8.40. Percentage of large-hydro plants in portfolios of the IPP groups

	0-60 th Month	61-120 th Month	120-180 th Month	180-240 th Month
Player 12	9	9	7	1
Player 13	7	4	2	0

Table 8.41. Percentage of lignite plants in portfolios of the IPP groups

	0-60 th Month	61-120 th Month	120-180 th Month	180-240 th Month
Player 12	6	6	4	0
Player 13	7	4	2	0

Table 8.42. Percentage of diesel-oil plants in portfolios of the IPP groups

	0-60 th Month	61-120 th Month	120-180 th Month	180-240 th Month
Player 12	9	9	7	1
Player 13	12	9	7	4

Table 8.43. Percentage of geothermal plants in portfolios of the IPP groups

	0-60 th Month	61-120 th Month	120-180 th Month	180-240 th Month
Player 12	6	6	4	39
Player 13	17	14	12	9

8.3.10. Performance Evaluation of the Active Players, who Selected the IPP Role

The effects of the decisions of Player 12 and Player 13 on the market and on the cumulative profits of the players themselves are explained below.

As illustrated in Figure 8.23, after the first quarter of the planning horizon, excess capacity ratio in the trial of Player 12 is higher than that of the case for Player 13 (because Player 13 withheld a larger portion of his available supply than Player 12 did).

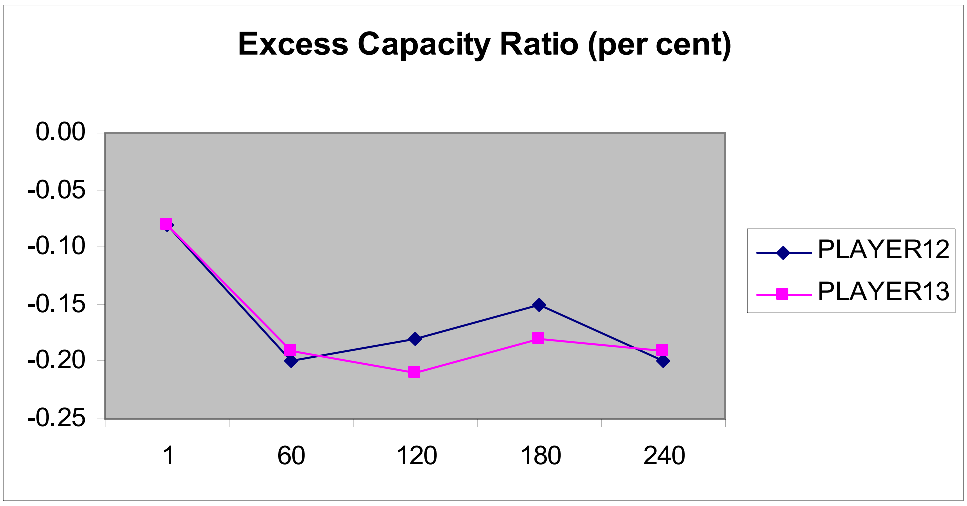


Figure 8.23. Excess capacity ratio in trials of the players, who selected the IPP role

Due to two major reasons, listed below, bid prices offered by the Player 12 are lower than the bid price offered by the Player 13.

i. As illustrated in Tables 8-36-8.43, Player 13's power plant portfolio includes more thermal power plant types as compared to the Player 12's portfolio. (Player 12's portfolio is richer in hydropower plants.) Here, it should be noted that unit production cost of thermal plants is distinctly higher than that of the hydropower plants.
ii. As the profit margin of the Player 12 is lower than that of the Player 13, bid prices of the Player 12 are lower than those of the Player 13, as well.

High bid prices of any investor directly affects the pool prices if there is supply gap in the market. As there are supply gaps in the trials of Player 12 and Player 13, pool prices directly depend on all of the investors' bid prices. As previously explained, bid price of

Player 13 is higher than that of Player 12. Consequently, average monthly pool prices in the trial of Player 13 are higher than that of the case for Player 12, as presented in Figure 8.24. Additionally, having lower excess capacity ratio in the trial of Player 13, as compared to the trial of Player 12, is another reason of having higher pool prices in Player 13's case.

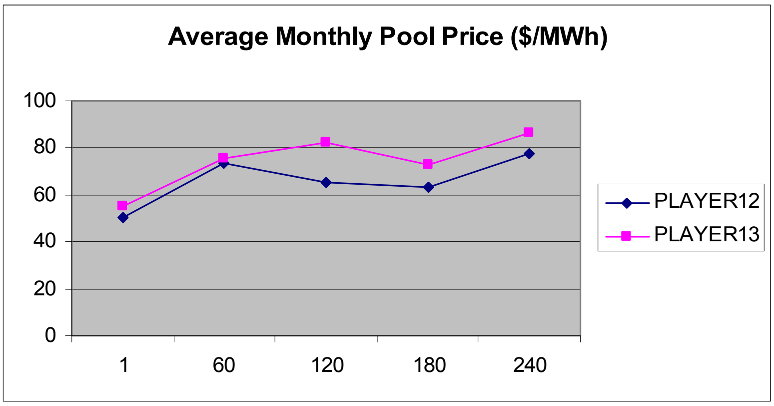


Figure 8.24. The average monthly pool prices in the trials of the players, who selected the IPP role

Figure 8.25 illustrates the cumulative profits acquired by Players 12 and 13 throughout the entire planning horizon. Since pool prices in the trial of Player 13 are higher than that of the case for Player 12 and there is not any risk for the investors selling less than their available supply, owing to the supply gap in the market, Player 13 gained more profit than Player 12 did. It should be noted that, Player 13 had more profit than Player 12 did, despite;

- Player 13 made less investment than Player 12 did.
- Player 13 withheld a larger portion of his available supply, as compared to Player 12.
- The investments, Player 13 made during the planning horizon, concentrated on thermal plant types, which have higher unit production costs, in comparison to the renewable power plants.

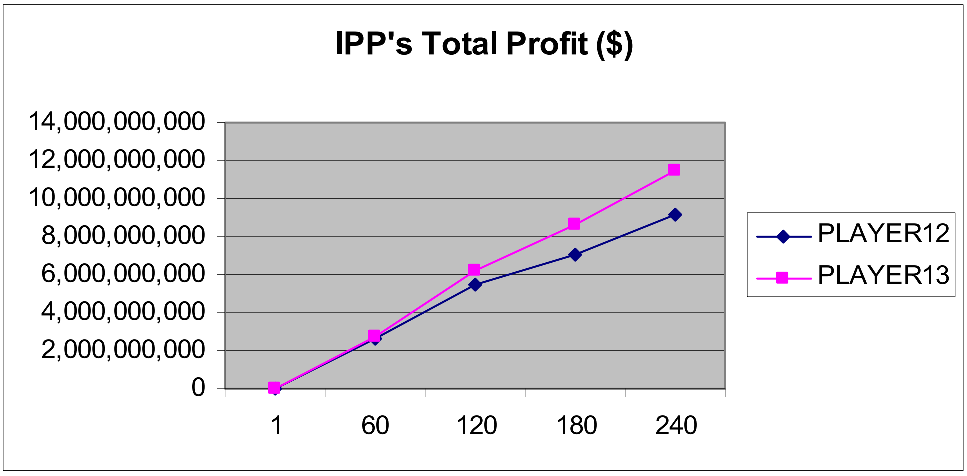


Figure 8.25. Total profit of the players, who selected the IPP role

Another point to note is that cumulative profits of the Incumbent and the NE are higher in the trial of Player 13 than in the trial of the Player 12, because of the high pool prices caused by the withholding of Player 13. Figure 8. 26 and Figure 8.27 illustrates cumulative profits of the Incumbent and the New Entrant, respectively.

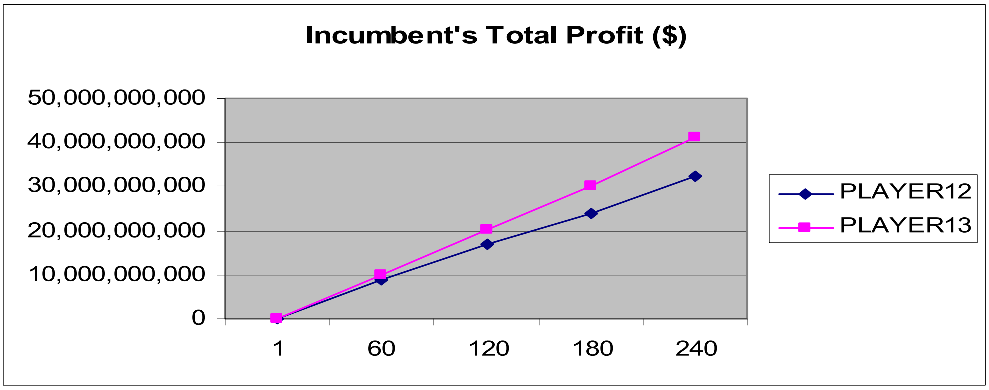


Figure 8.32. Total profit of the Incumbent in the trials of the players, selected the IPP role

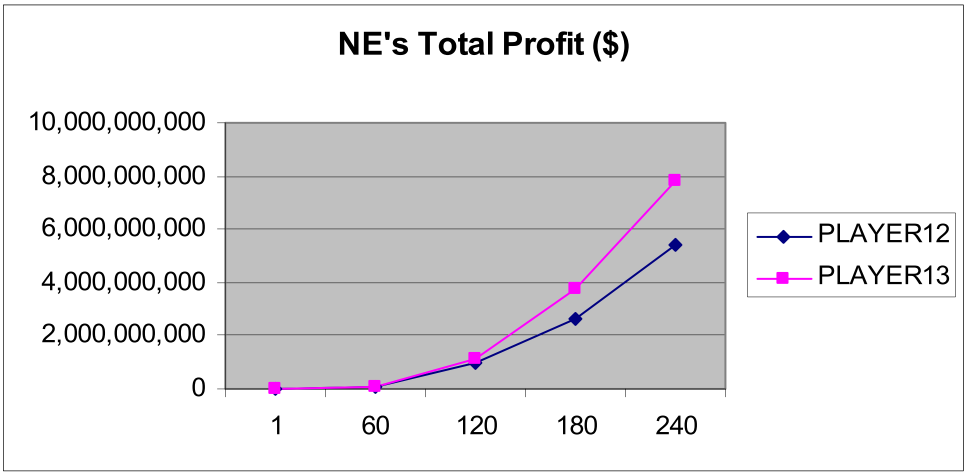


Figure 8.33. Total profit of the New Entrant in the trials of the players, selected the IPP role

8.3.11. Potential Contribution of the LEMM to Learning and Teaching

Electricity industry restructuring involves a great deal of interdisciplinary concepts, including economic, commercial and environmental aspects of the restructuring process. Consequently, the resulting system is complicated and changes continuously, thereby making history almost irrelevant. Accordingly, decision makers, researchers and students need more than case studies discussing, explaining and projecting on the past experiences. Actually, the LEMM is developed precisely due to this reason. By means of such a decision support tool, investors, Regulators and researchers will have the opportunity to understand possible consequences of different decisions that they may make under different policies and market conditions. Moreover, such a tool is a risk-free way for managers to gain experience in a competitive environment which they are not familiar with.

Additionally, nowadays introductory courses related with electricity market dynamics have been added to the curriculum in many universities. On the other hand, as previously mentioned, the electricity market dynamics, depending on various interdisciplinary concepts, are complicated. Consequently, it is not straightforward for students to understand the dynamics of the electricity market, so a teaching tool to assist students to better understand strategic behaviors in the market is thus in high demand.

After the experiments with the LEMM at the Sabanci University, the students reported that experimenting with the LEMM have much improved their understanding of the dynamics of the electricity market. They stated that it was a good opportunity for them to share this experience and analyze market behavior through experimentation with the LEMM.

9. CONCLUSIONS

In centralized and regulated electricity markets, power plants investment decisions used to be the result of an optimized centralized capacity expansion planning (at national or regional level). The aim of this planning was to determine the right level of generation capacity, the optimal mix of generation technologies and the timing of the investments and retirements, to ensure that future demand in a certain region would be served at minimum cost, with an adequate level of reliability. In such an environment, the future demand and future fuel prices were the only significant sources of uncertainty.

After the deregulation and liberalization of the electric power sector, capacity expansion decisions are made by multiple, independent and self-oriented power companies. Unlike the regulated environment, decision-making of market participants is now guided by price signal feedbacks and by an imperfect foresight of the future market conditions that they will face. In such an environment, decision makers need to better understand the long-term dynamics of the supply and demand sides of the power market, as sound investment decisions depend on it. However, since deregulation is a revolutionary process that introduces new rules to the market, it renders history almost irrelevant. As a result, decision makers need a decision tool which focuses on learning and understanding the system (instead of predicting the future based on the historical data) and offer sets of possible scenarios of the future that can be studied to acquire additional insight.

To meet the needs stated above, a simulation model, mimicking the behavior of the competitive electric power market, based on System Dynamics (SD) philosophy has been proposed and developed in this thesis. Since, SD is a descriptive method, which focuses on learning and understanding the system (instead of predicting the future), so does the developed model. The developed model represents the electricity market in detail: it includes;

i. a detailed demand module, conveying monthly and hourly variability in electricity demand and featuring price elasticity of demand;

ii. a capacity expansion module, considering eight different power plant types;

iii. accounting and financial modules, tracing balance sheets, financial status and credibility of each investor;
iv. a bidding mechanism, determining pool prices and electricity supplied from each producer;
v. up to five competitors, differentiating from each other in terms of their power plant portfolio, liquid assets and behavior types.

Additionally, various factors and options (such as investors' aggressiveness level and withholding tendencies, tax issues, capital structure of the investors, subsidies/surcharges, seasonality effects, presence of long-term contract in the market and capacity addition limits on power plant types) are considered in the model. Besides, to construct one of the scenario options offered in the developed SD model, an AHP study, with the aim of comparing and evaluating plant types, is conducted. (The results obtained through the AHP study revealed that the most preferred plant types are hydro, natural gas and wind plants, whereas the least preferred is nuclear plants.). The plant types considered in the SD model are then formed based on the results acquired through the AHP study.

During the modeling process, various submodels have been developed and tested before they were integrated to form a complete system model. At each phase of modeling, besides international literature, expert opinions have been considered in determining the model structure, relationship between entities, parameters and equations used in the model, to ensure the representativeness and the reliability of the model.

The model is structurally validated through extreme condition tests and sensitivity analysis. However, due to lack of data, model parameters could not be calibrated. Although sufficient confidence is established on the model structure, the model requires further calibration in case of decentralized electricity market data becoming available.

The model has a flexible structure for parametric studies, such that values of the parameters affecting the market can be altered and the results of selected strategies/policies (set of parameters) can be analyzed. Total number of possible scenarios that can be simulated is 227.812.500.000.000, (considering all combinatorial interactions between parameters and strategies.) Evaluating all these scenarios would require vast amount of computation and analysis time. So, a limited scenario set, consisting of 128 scenarios, has been configured, run and analyzed through a two- phase approach, to pursue the effects of capacity withholding, presence of long-term contracts, price elasticity of electricity demand, CO_2 tax, state support for renewable energy, various tax issues, debt-ratio for a new investment, seasonal effects on capacity factors of wind and hydropower plants, VOLL, forecast period of the investors and aggression level of the investors, on short-term and long-term performance of the electricity market. The major findings acquired through the two-phase scenario analysis are briefly explained below;

- The finding forwarded in this paragraph is named as the “investment/business cycle”. In times of excess capacity, the electricity price is too low to attract new investment. The low prices push up the demand, while discouraging new investments. However, when high demand exhausts the available supply, prices quickly rice. During these price spikes, investors gain considerably high profits, which then attract new investments. However, additional generation capacity becomes available after long construction times. As a result, the electricity price tends to oscillate, with high spikes, depending upon the annual demand growth rate, the investment cost and the construction times. In other words, there exists boom and bust cycles in the electricity reserve margin (excess capacity). The finding stated above is in line with the observation brought forward by (Ford,1999a), who forecasted the possible development of a generation construction cycle in California about a year before the crisis developed. Moreover, (Borenstein, 2001) agrees that the extremely low elasticity of both supply and demand cause price volatility, which is exacerbated by the capital-intensiveness of power plants, with boom-and-bust cycles in excess capacity as a likely outcome.
- Since the electricity demand curve shifts continuously, generating companies face daily and hourly variations in demand. As a consequence, in all of the simulation outputs (of 128 scenarios), there exists tooth-saw patterns in the electricity reserve margin and pool prices during, the entire planning horizon.
- The investors invest in power plants with high variable cost and investment cost (such as diesel oil and wind plants), only in the presence of high pool prices in the market. In other words, presence of mechanisms, resulting in high pool prices (such as withholding and high VOLL), cause the investors to diversify and invest in diesel

oil and wind power plants, as well as the other plant types. Here, it is important to note that although wind plants are among the first three most preferred plant types according to the results obtained via AHP study, SD model reveals that these plant types are preferred by the investors in the presence of high pool prices. The underlying reason of this difference between AHP and SD model is that in the AHP model, the investors take into consideration not only economic factors but social and economic factors, whereas in the SD model, the investors just focus on the economic issues.

- In all scenarios, natural gas and small hydro-power plants (owing to their low investment costs) are speedily built until the country's all potential is fully utilized.
- The dynamic behavior is dominated by the market feedback formed by investors' expectations and by the plant construction delays. Simulation results show that investments in power plants do not always keep pace with demand growth and capacity retirements. Imperfect foresight, and most importantly, investment decision and construction delays prevent timely and sufficient adjustments in production capacity. This leads to fluctuating reserve margins, and consequently, to volatile long-run market prices.
- Withholding raises the market price and causes competitors to enter the market with new plants investments. In the presence of withholding, due to higher prices in the market, capital intensive plant types, (namely large hydro, lignite and imported hard-coal plants) became attractive to investors. As a consequence, total installed capacity of these plant types is much higher when there is withholding in the market. Therefore, due to increasing installed capacity (i.e. increasing excess capacity), the Incumbent's market share and pool prices decrease in the long-term. Besides, in case of demand elasticity, the presence of withholding (and the resulting price increases) trigger a decrease in the demand/demand growth rate, which in turn cause an excessive installed capacity, a decrease in the market price and a rebounce in demand/demand growth rate. To sum up, the overall effect of withholding is an oscillation in the overall electricity demand.
- The presence of long-term contracts in the market dampens average monthly pool prices. Therefore, new investment/new entry becomes less attractive to the investors and consequently total installed capacity throughout the planning horizon remains lower, as compared to the cases without long-term contracts (This finding is parallel

to the findings presented in (Gans *et al*., 1998). As a consequence, the Incumbent keeps his high share for a longer period. In case there are long-term contracts in the market, the amount of the demand that is prone to be effected by withholding is lower (as compared to the market without long-term contract), since a portion of the demand is guaranteed to be supplied at a predetermined price. As a result, the presence of long-term contracts in the market dampens the height of the price spikes caused by withholding.

- As the forecast period, used in projecting the supply-demand gap and the pool price, increases, investors build more plants. Consequently, it can be said that the electricity reserve margin increases as forecast period increases. Moreover, as the electricity reserve margin increases, the SMP and the average monthly pool prices decrease. As a result, in the presence of price elastic demand, annual peak demand at the end of the planning horizon is higher, as compared to that of the case in scenarios with lower forecast period. Since excess capacity ratio, in the cases with longer investors' forecast period, is higher than that of the cases with shorter forecast period, the purchased portion of each investor's available supply in the cases with higher forecast period is lower than that of the cases with lower forecast period. As a result, monthly oscillations in the investors' market share is higher in the cases with longer forecast period. Due to this reason and the lower average monthly pool price, cumulative profits of the investors are lower, as compared to the cases with shorter forecast period. Furthermore, in the long forecast period, the electricity market is less sensitive to withholding, as compared to markets in the low forecast period case, thanks to the presence of higher reserve margins. Consequently, extra profits earned due to withholding is lower, as compared to the cases with shorter forecast periods.
- The major effect of the state support for renewable plants is changes in the plant portfolio composition in favor of large hydro and geothermal plants, and consequently a decrease in the system marginal price. As the construction time for hydro plants is comparatively longer than other plant types, when investors prefer to invest in such plants, the growth rate for installed capacity remains lower than the demand growth rate, which in turn causes prices to increase and demand (if price elasticity is non-zero) to decrease. Besides, state support for renewable energy acts as an inducement for competitors to enter the market with new plant investments, which in turn reduces the market share of the Incumbent.

- In the presence of tax exemption, the investors are not asked to pay any tax unless their total profit exceeds a predetermined percentage of their investment costs. As a consequence, investments (especially in more capital intensive plant types) become more attractive to the investors. As tax exemption functions as an investment incentive, total installed geothermal, large-hydro, diesel-oil and imported hard-coal power plants and the overall total capacity are higher both during and at the end of the planning horizon (as compared to the cases without tax exemption). On the other hand, investors' net profits are also higher (as compared to the scenarios without tax exemption), since the investors do not pay taxes before a prescribed portion of their investment is paid back.
- Total installed capacity throughout the planning horizon increases as the debt-equity ratio increases, since cost of debt is lower than cost of equity (as interest payments on loans are free from tax). As the debt-equity ratio increases, investors invest more in highly capital-intensive plant types. As the debt-equity ratio increases, the IPPs and the NE become more apt to new investments. As a result, total installed capacity of the NE and the IPPs are higher, at the end of the planning horizon, as compared to the cases with lower debt-equity ratio. As a consequence, the Incumbent's market share is lower than that of the case with lower debt-equity ratio.
- As the major part of the existing power plant portfolio is thermal power plants, imposing CO_2 tax causes the pool price to increase. As a consequence, in the presence of price elasticity of electricity demand, due to the CO_2 tax (and the resulting price increase) demand/demand growth rate and new investment amount decrease.
- In case of inelastic demand, imposing the CO_2 tax causes a shift in new investments from thermal plants to renewable plants, within the limits of the relevant reserves.
- Since, in the scenarios with annual capacity addition limits on hydro plants, investors make more investments in natural gas plants, there exists shorter investment cycles due to short construction times of the natural gas plants. As a result, during the intermediate years, the supply gap (in the scenarios with the annual capacity addition limit on hydro power plants) is less than that of the case without the annual capacity addition limit.
- Since aggressive investors' rate of return (ROR) expectation from new investments is lower in comparison to conservative investors, aggressive investors are more apt to

make new investments. As a result, in the scenarios with aggressive investors, the total installed capacity, and consequently the reserve margin, are higher in comparison to the scenarios with conservative investors. Besides, aggressive investors' profit margin is lower than conservative investors' profit margin. So, when the investors are aggressive, the average pool price is lower, due to the higher reserve margin and the lower profit margin of the investors.

The results obtained through the two-phase scenario analysis illustrate that liberalization of the electricity market can improve/deteriorate the social welfare depending on the Regulatory policies, restrictions and price mark-ups in the market. Due to this reason, depending on the policies in the market, liberalization can improve/deteriorate electricity market in terms of shortages, electricity prices.

The results also reveal that the model is able to capture most of the long-term dynamics which occur both on the supply and on the demand sides of the power market. Although the default parameters have been obtained from Turkish Electricity Market, the model can be used in other markets as well, by simply changing the parameters.

After the scenario analysis is completed, a user-friendly interface is integrated to the model, and the decision tool (Liberalized Electricity Microworld, LEMM) is developed.

The functionality, effectiveness, ease of use and educational capabilities of the LEMM are tested on 26 students of the senior level "Energy Policy and Planning" course at the Sabanci University. The students reported that experimenting with the LEMM have much improved their understanding of the dynamics of the electricity market.

Accordingly, we believe that while the design and development of the LEMM has been a valuable research experience associated with the analysis and modeling of decentralized and deregulated electricity markets, the resulting system (i.e. the LEMM) is an excellent tool to be used in understanding, investigating and experimenting on a decentralized electricity market, especially in regard to investor behavior; supply, demand and price fluctuations, short and long term effects of various decisions and resource limitations.

As a future study, technology progress (learning curves of energy technologies) and relationship between fuel costs and primary energy resources' depletion may be considered in the SD model as endogenous parameters. Actually, the LEMM is flexible to to add these features easily. Additionally, transmission line constraints and costs can be considered in the developed model and consequently, the investors' investment decisions, investors' bid price decisions, pool prices can be determined by considering the transmission line constraints and costs. On the other hand, throughout the investment decision, investors can consider regional investment costs of power plant types, regional primary energy resources' availability and regional electricity demand, instead of average investment costs and country's overall primary energy resources' availability and electricity demand, since the related values vary depending on the geographical conditions.

APPENDIX: CD-ROM CONTAINING SIMULATION OUTPUTS

In this appendix, the contents of submitted CD-ROM at the back cover is explained. In this CD-ROM, a "read.me" text file, and the simulation outputs, which are given as excel files, explained in Chapter 7, are involved.

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2	Aggressive	NO	NO	5	NO
3	Conservative	yes	NO	5	NO
4	Aggressive	yes	NO	5	NO
5	Conservative	NO	yes	5	NO
6	Aggressive	NO	yes	5	NO
7	Conservative	yes	yes	5	NO
8	Aggressive	yes	yes	5	NO
9	Conservative	NO	NO	8	NO
10	Aggressive	NO	NO	8	NO
11	Conservative	yes	NO	8	NO
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15	Conservative	yes	yes	8	no
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31	Conservative	yes	yes	8	yes
32	Aggressive	yes	yes	8	yes
Elasticity	Capacity Addition Limit	VOLL	CO2 Tax	Incentive	
-0.5	no capacity addition limit	2000$/MWh	0	40% tax exemption for all	

Scenario	Elasticity	Cap. Addition Limit	VOLL ($/MWh)	Incentive for REN	CO2 Tax ($/kg)
33	0	NO	2000	0	0
34	-0.5	NO	2000	0	0
35	0	yes	2000	0	0
36	-0.5	yes	2000	0	0
37	0	NO	3000	0	0
38	-0.5	NO	3000	0	0
39	0	yes	3000	0	0
40	-0.5	yes	3000	0	0
41	0	NO	2000	20% gov.support	0
42	-0.5	NO	2000	20% gov.support	0
43	0	yes	2000	20% gov.support	0
44	-0.5	yes	2000	20% gov.support	0
45	0	NO	3000	20% gov.support	0
46	-0.5	NO	3000	20% gov.support	0
47	0	yes	3000	20% gov.support	0
48	-0.5	yes	3000	20% gov.support	0
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50	-0.5	NO	2000	0	0.0002
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53	0	NO	3000	0	0.0002
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55	0	yes	3000	0	0.0002
56	-0.5	yes	3000	0	0.0002
57	0	NO	2000	20% gov.support	0.0002
58	-0.5	NO	2000	20% gov.support	0.0002
59	0	yes	2000	20% gov.support	0.0002
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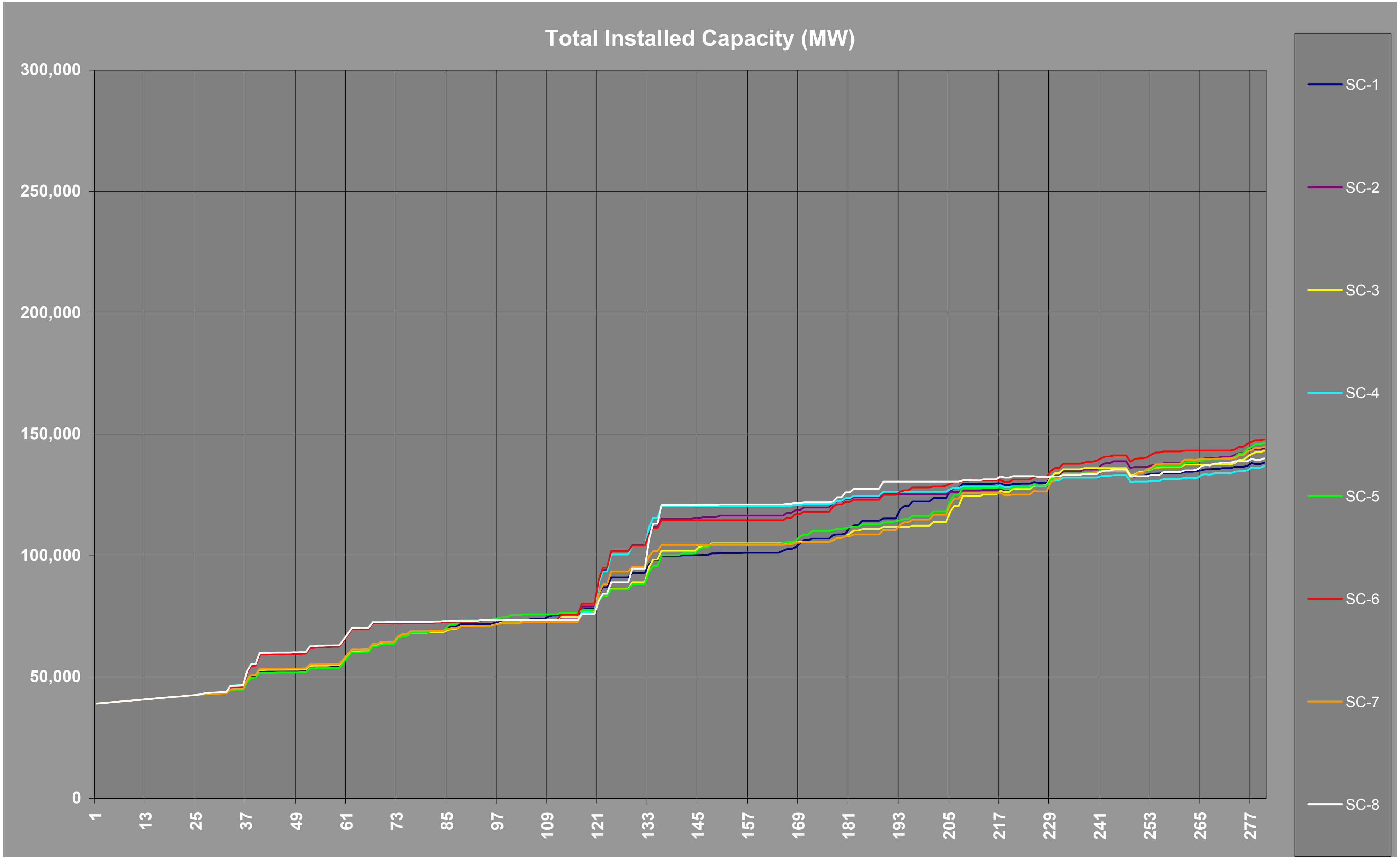
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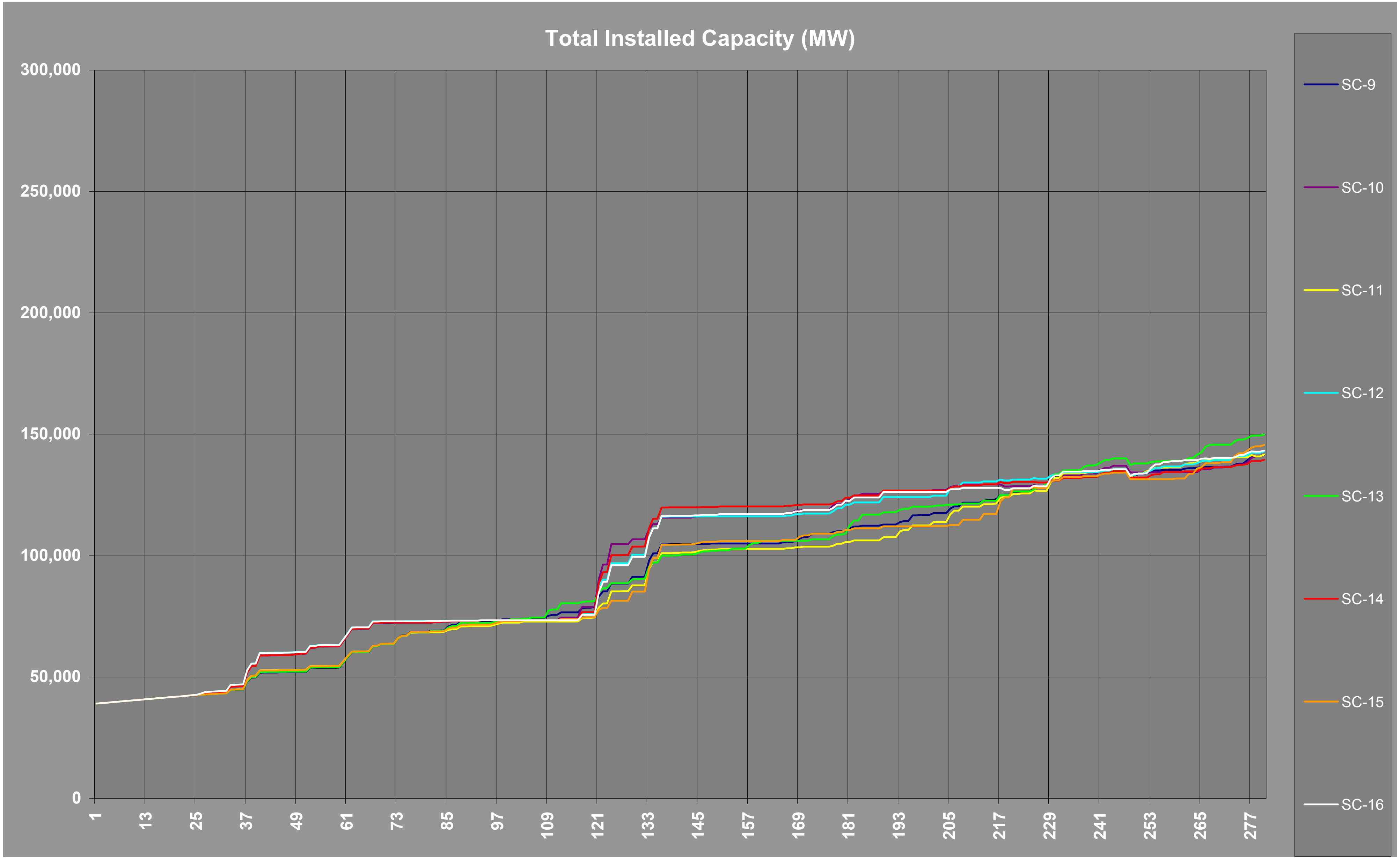
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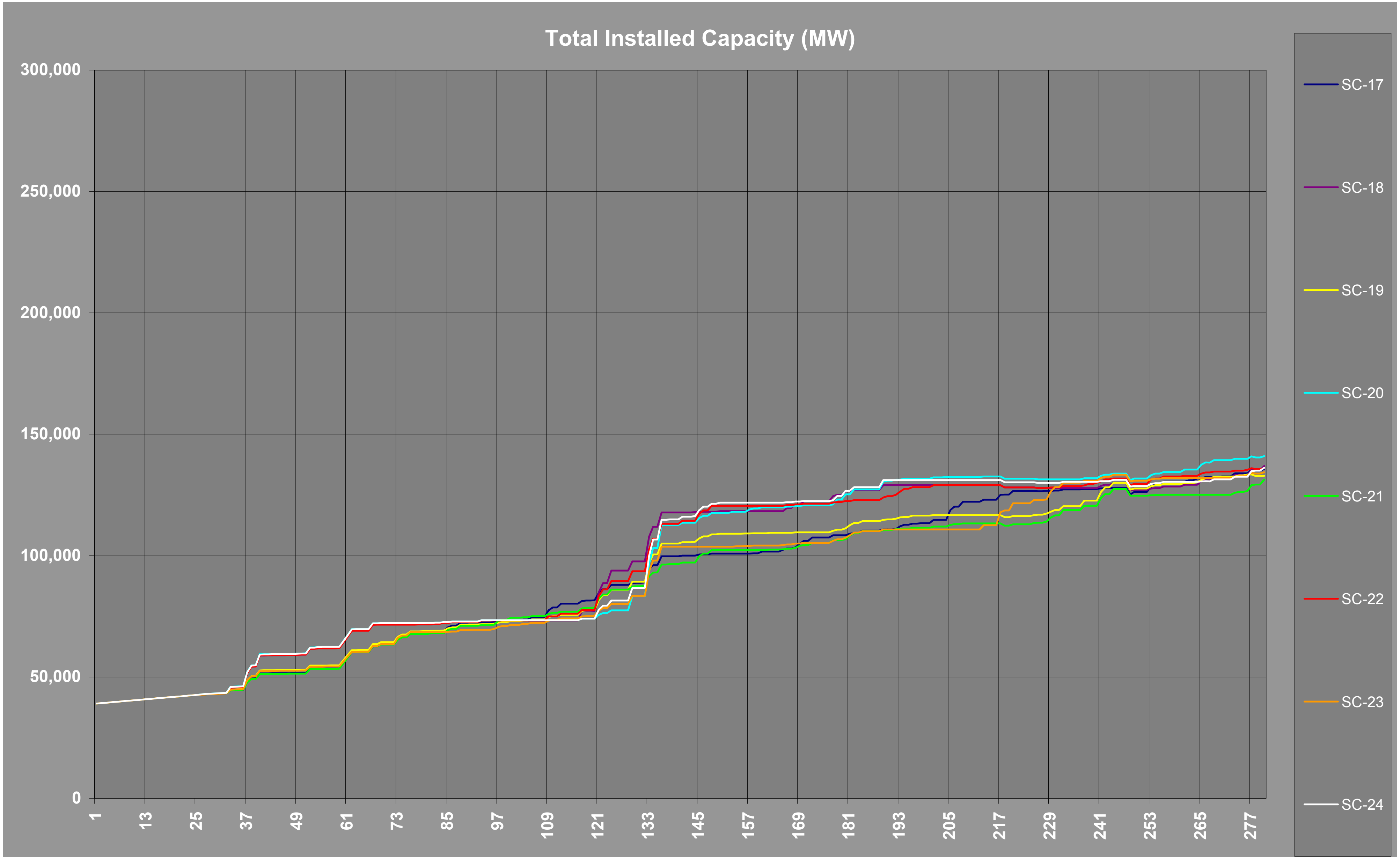

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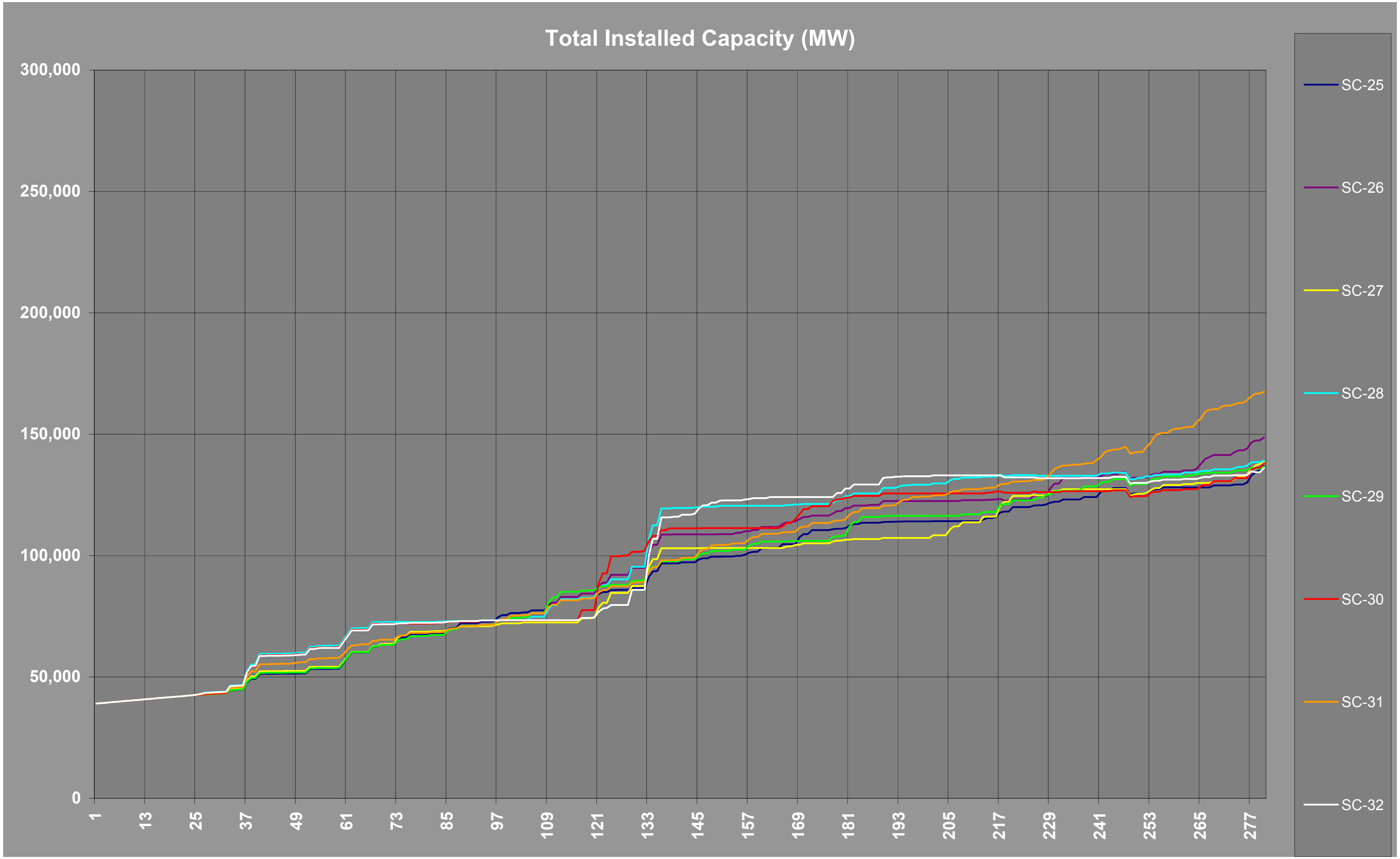
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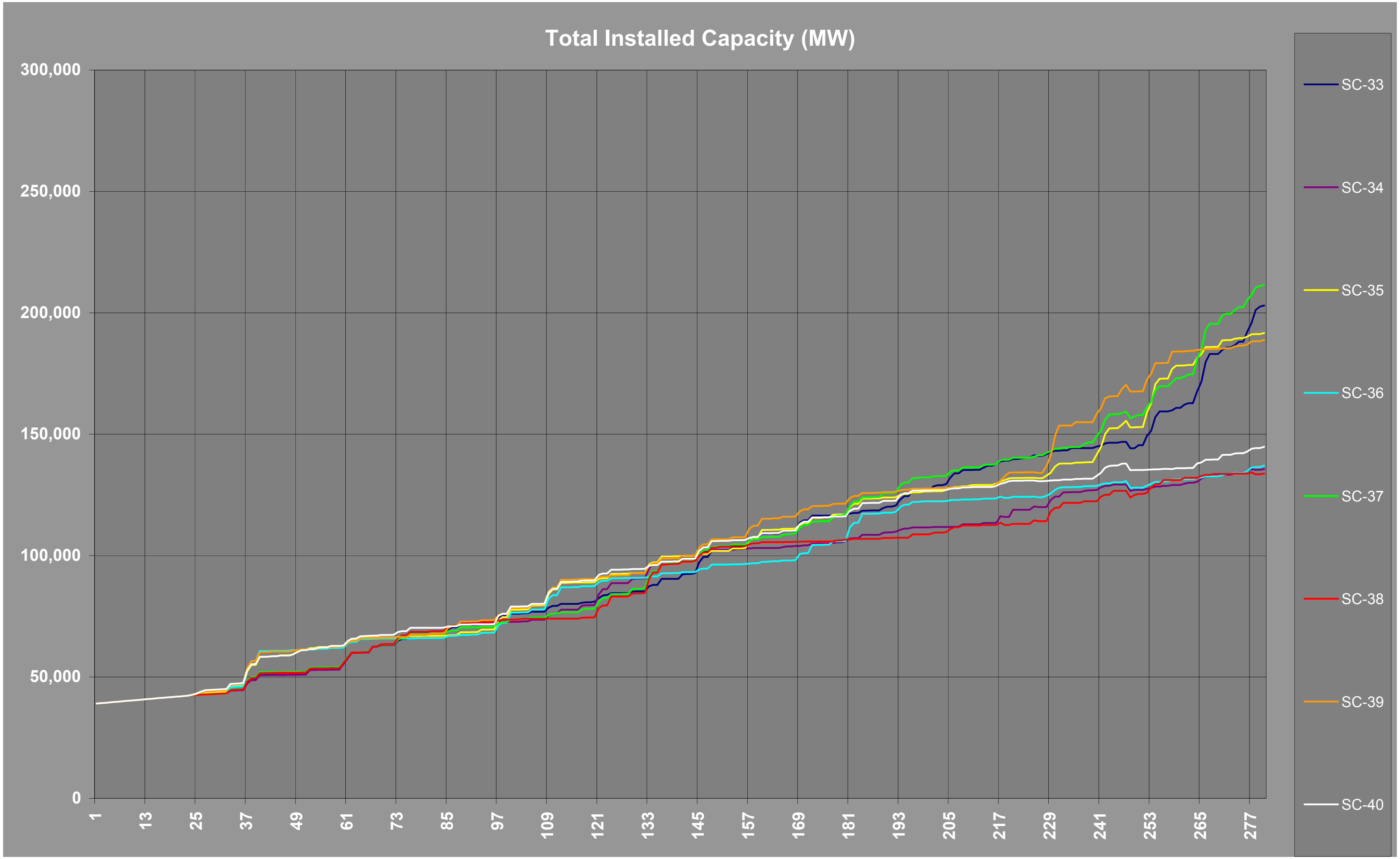

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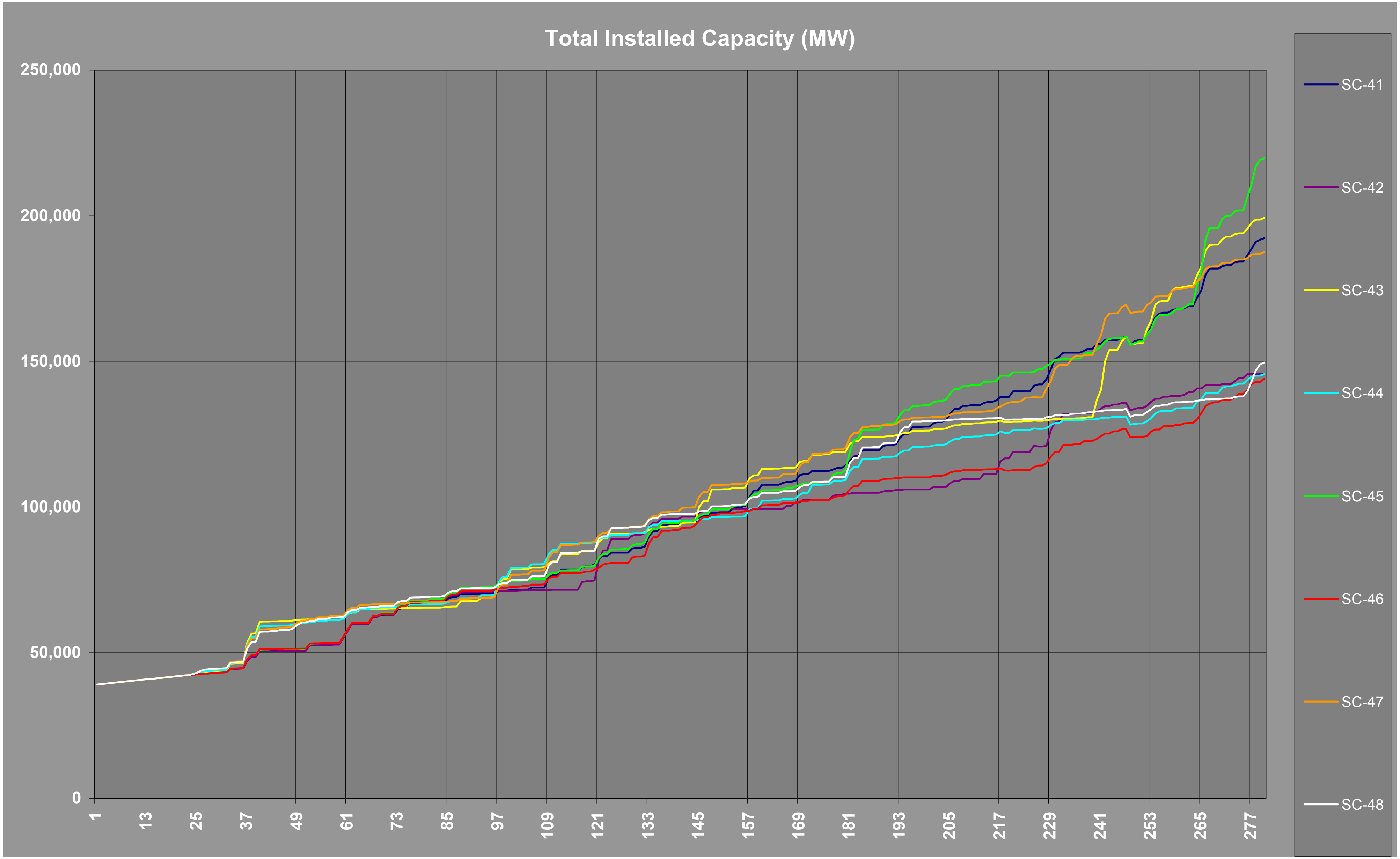
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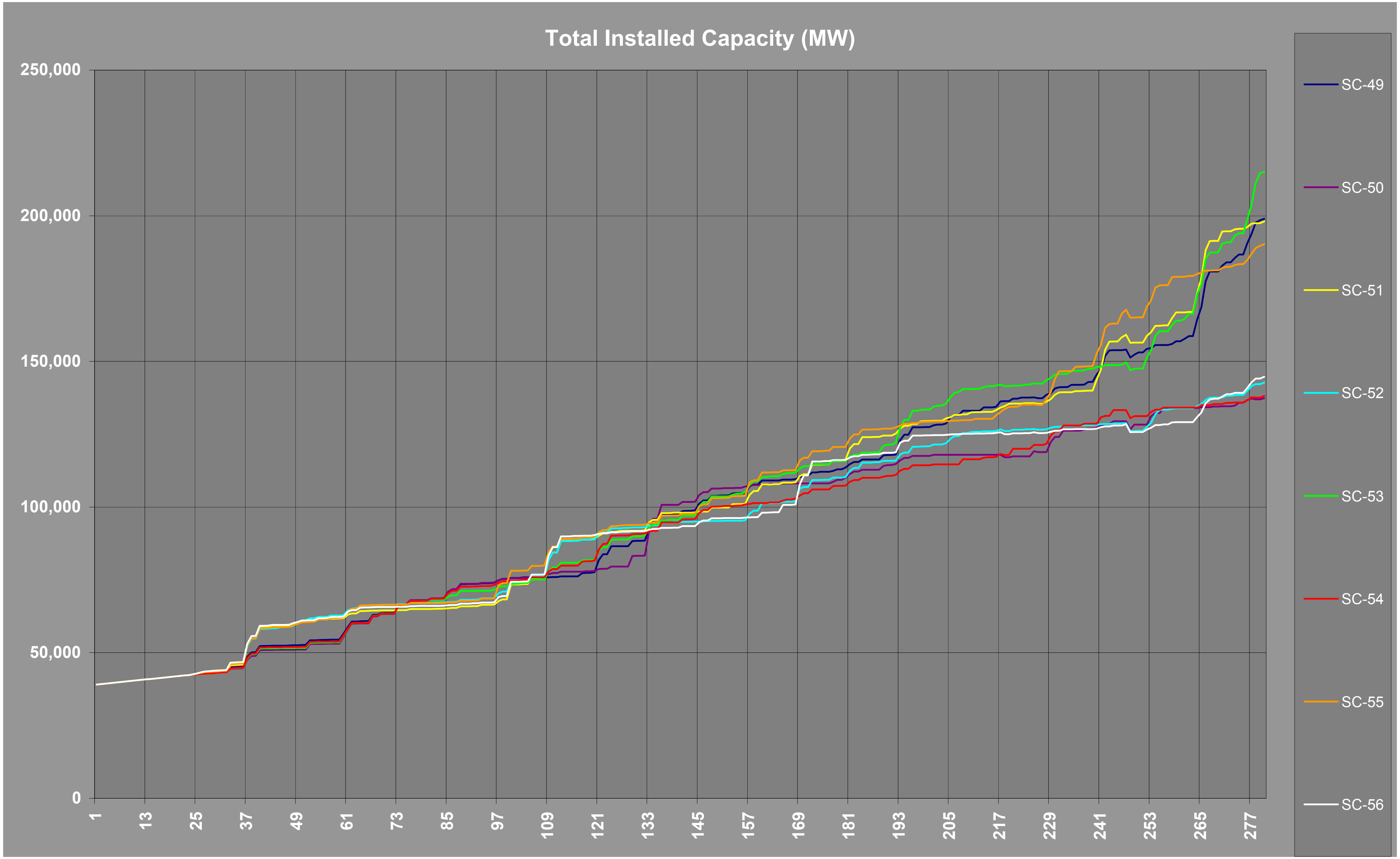
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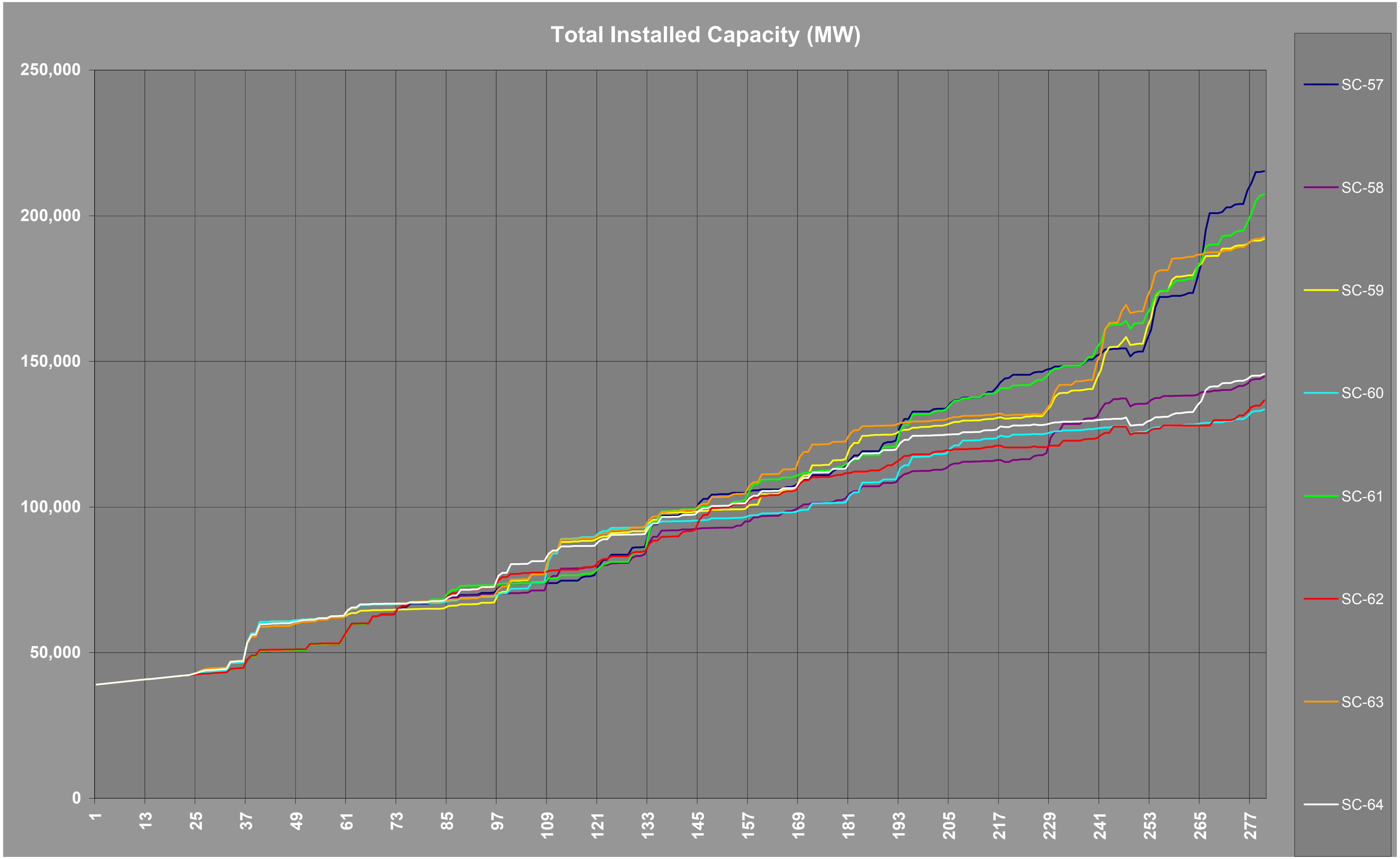

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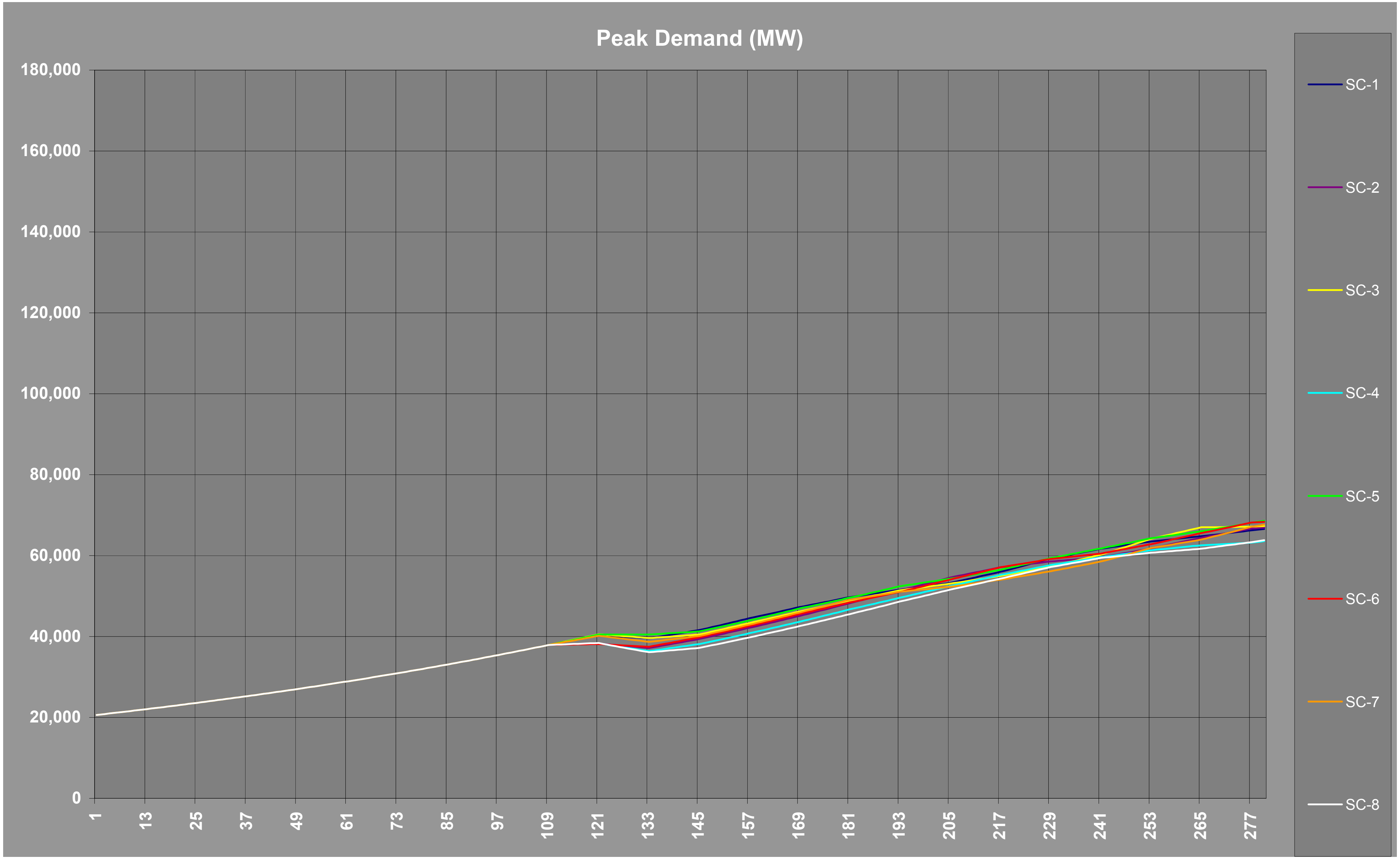

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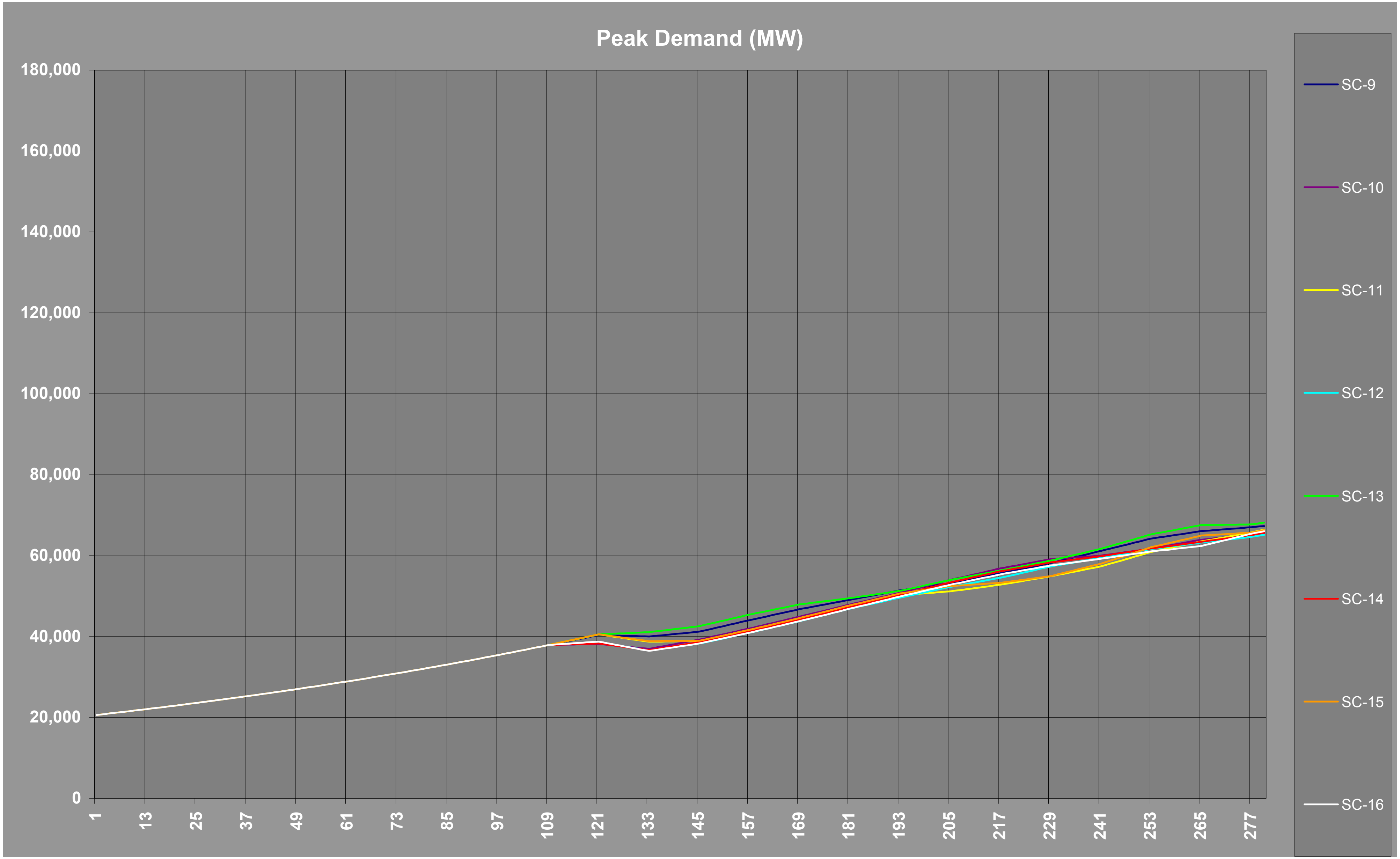

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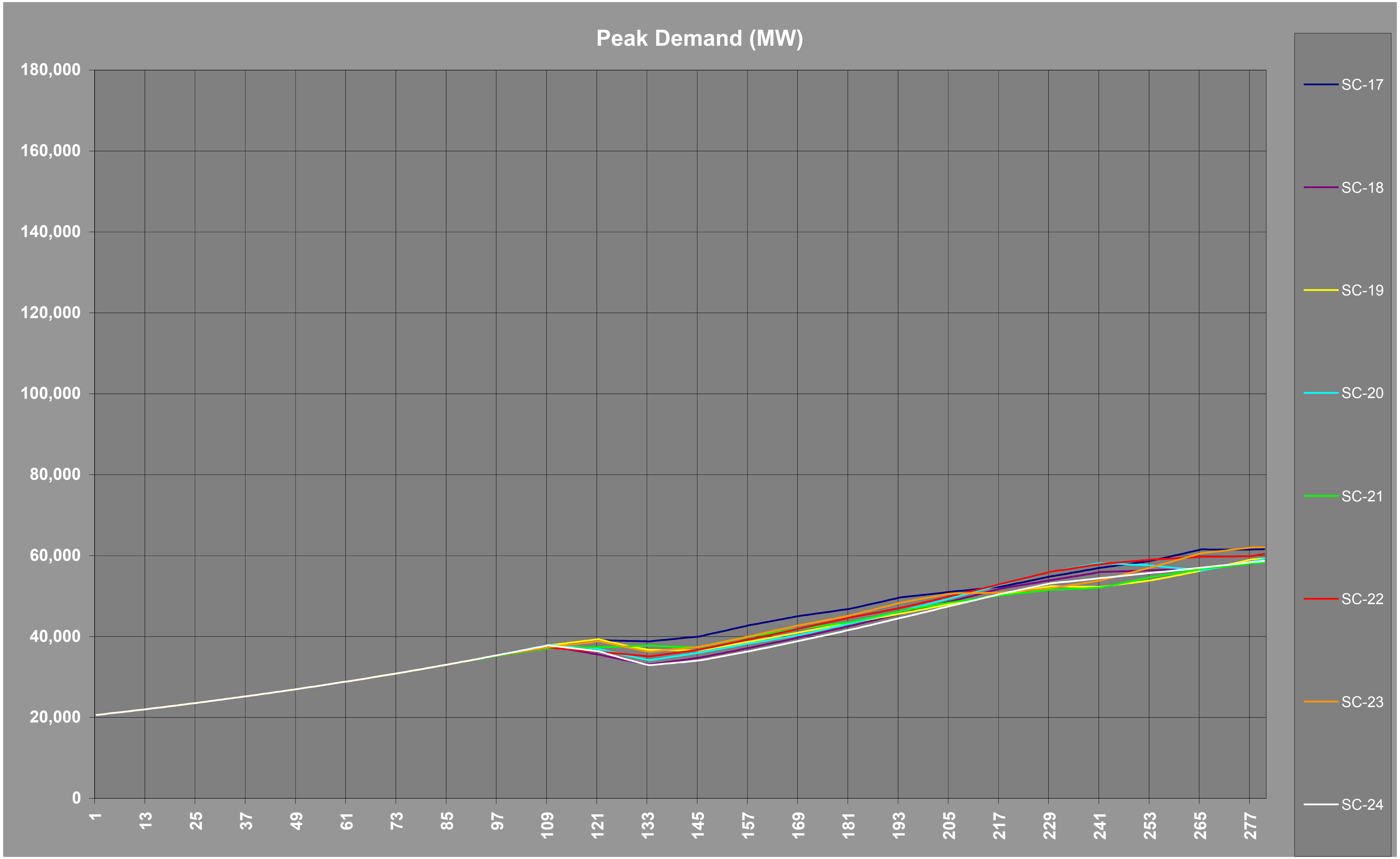
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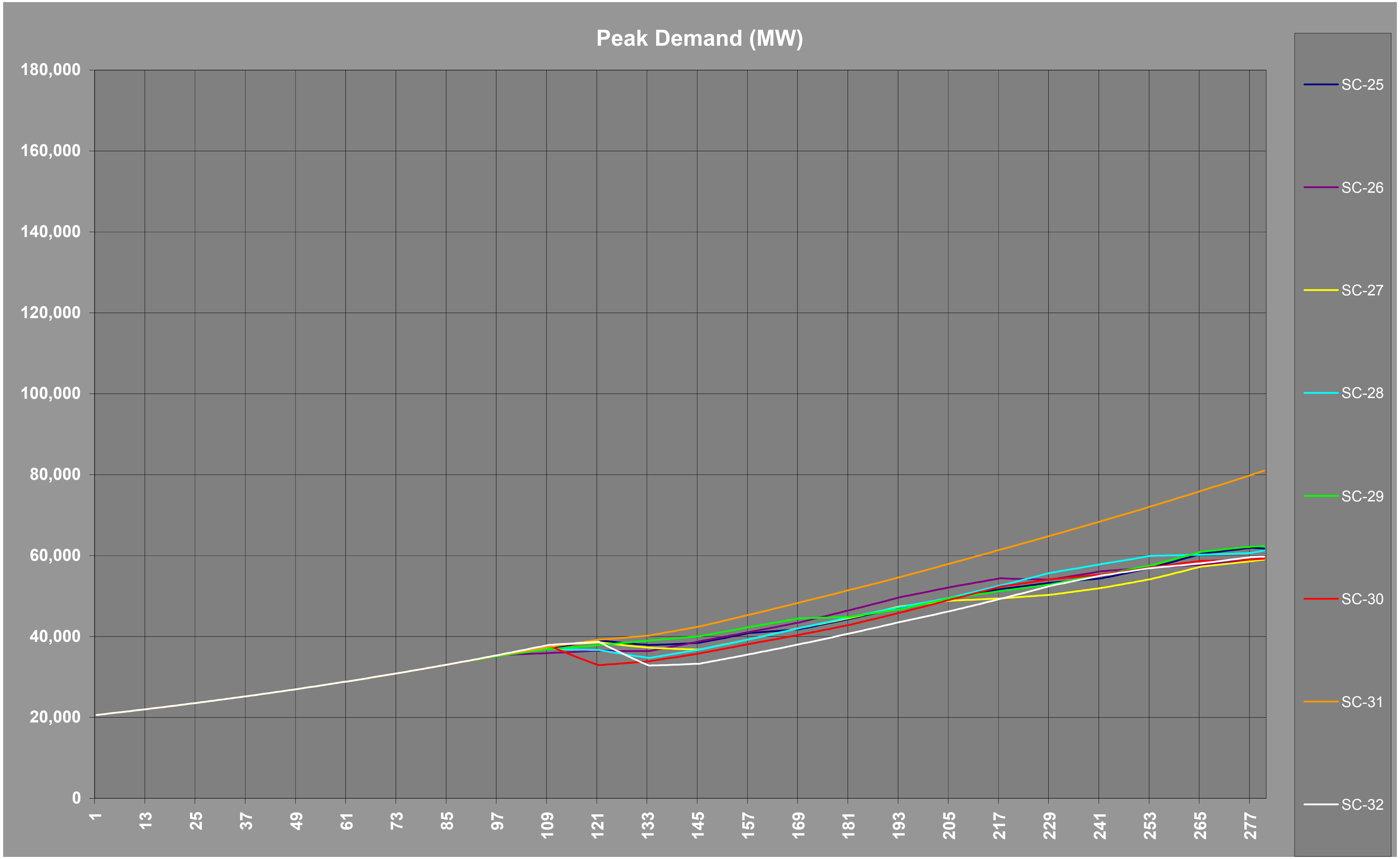

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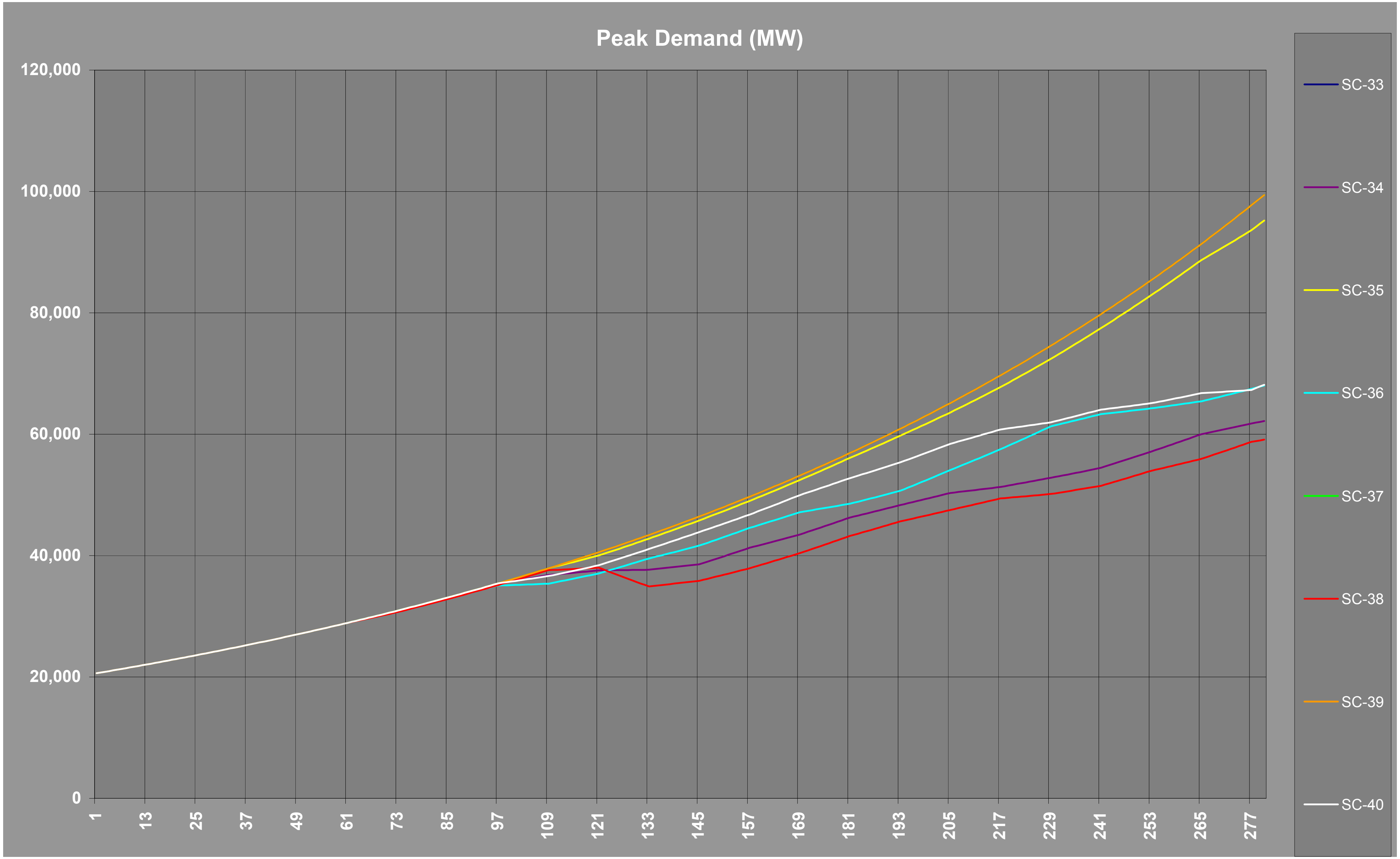

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145
157
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181
193
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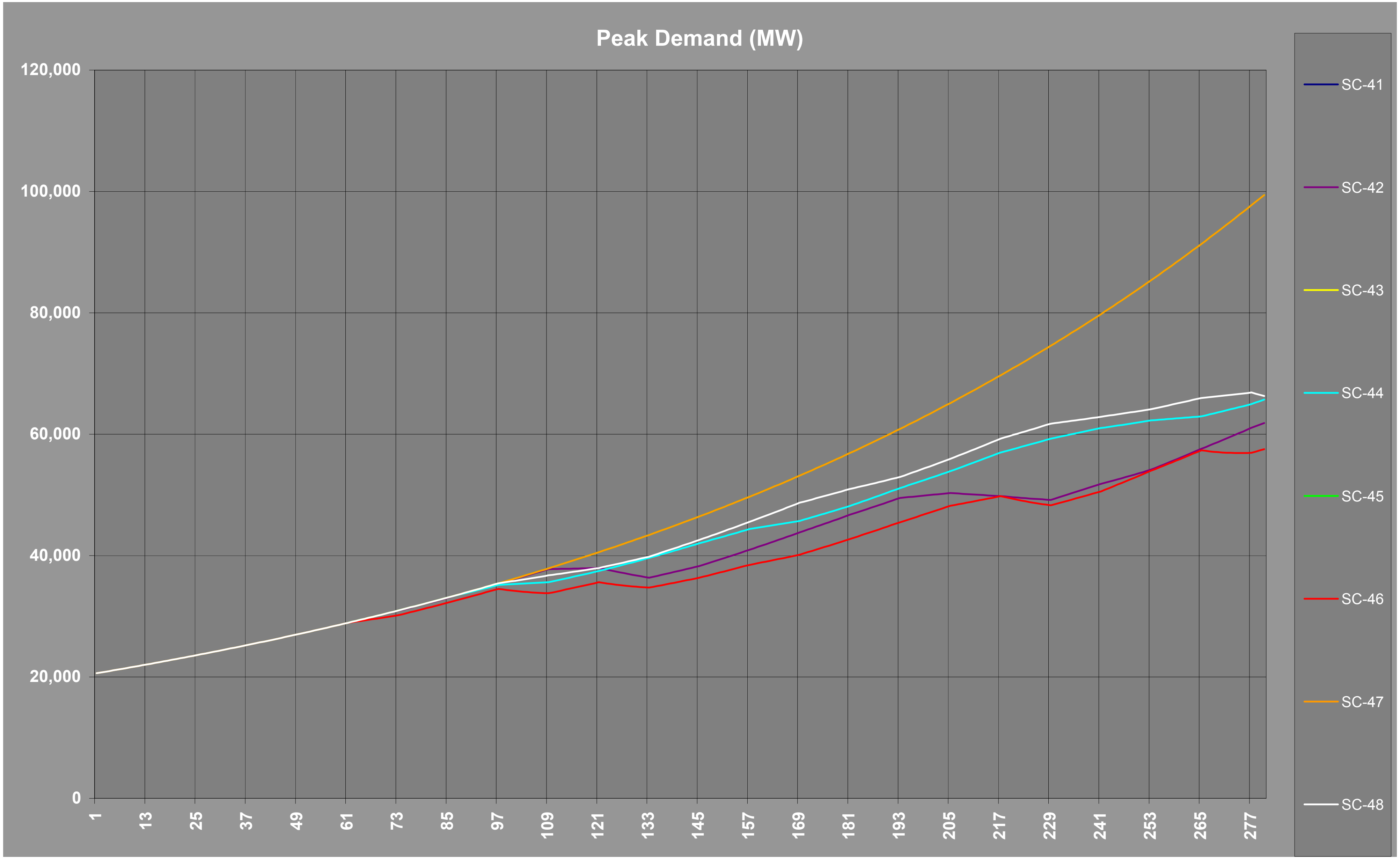
Peak Demand (MW)
120,000
100,000
80,000
60,000
40,000
20,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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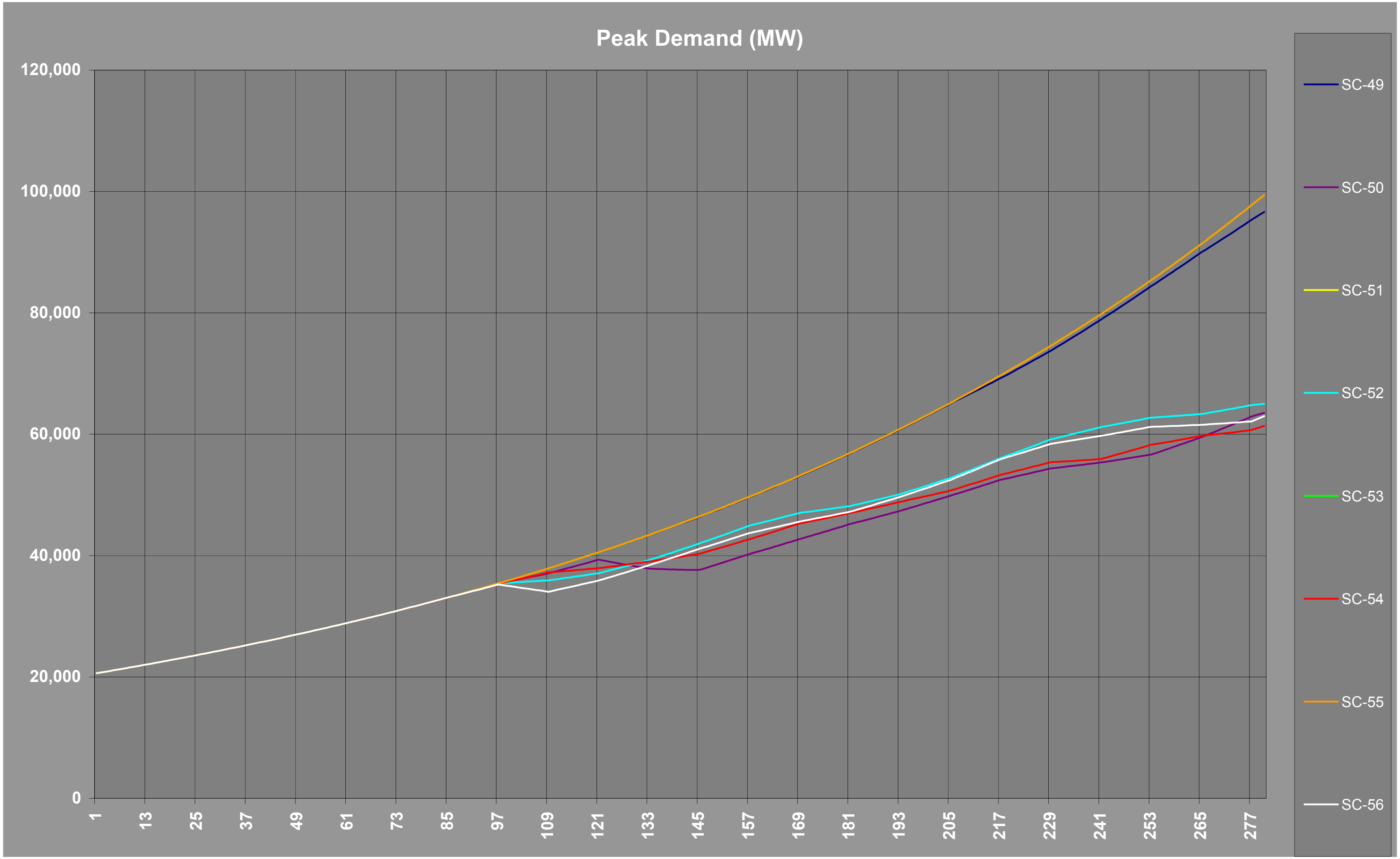
SC-47
SC-48


Peak Demand (MW)
120,000
100,000
80,000
60,000
40,000
20,000
0
1
13
25
37
49
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85
97
109
121
133
145
157
169
181
193
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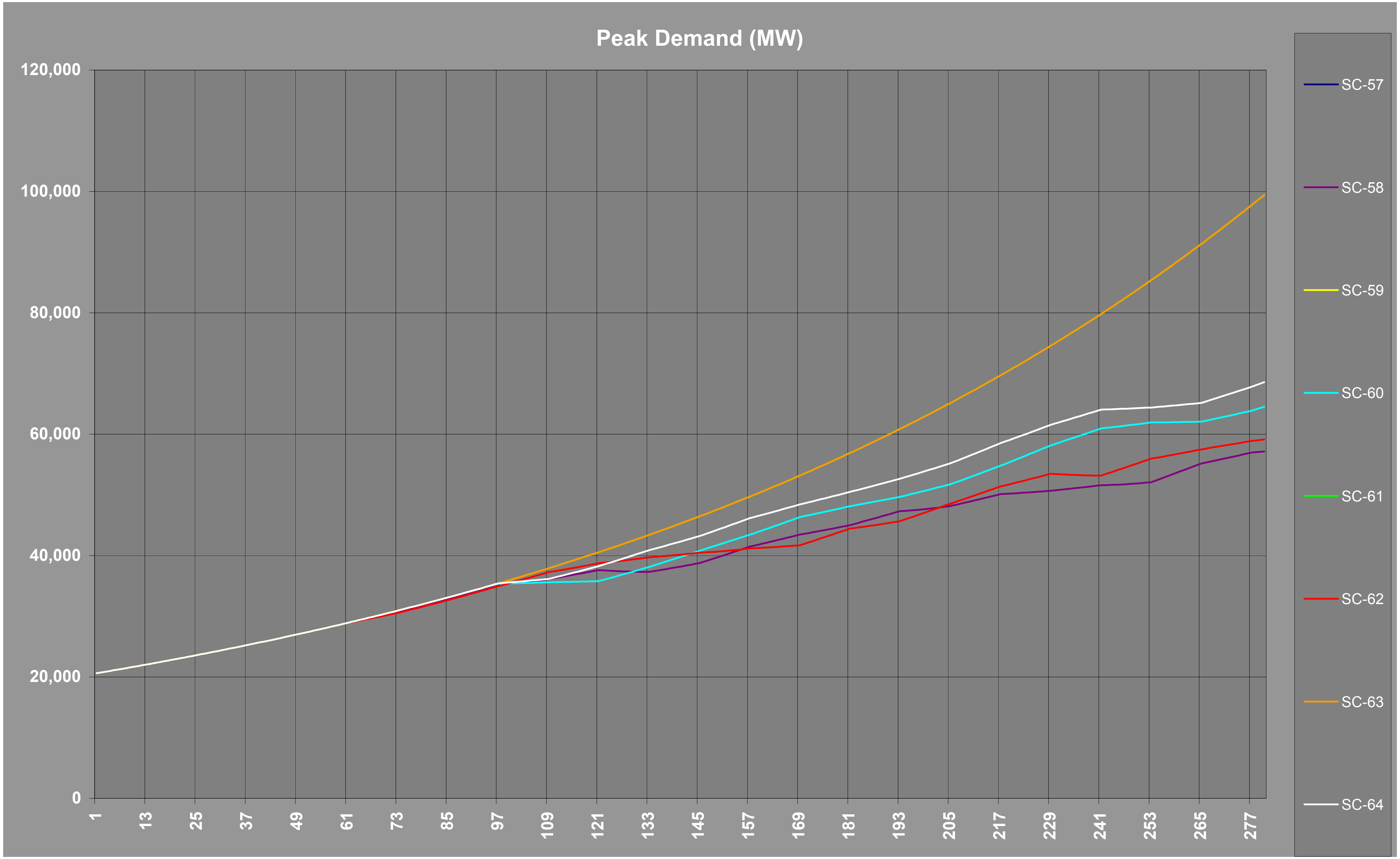
SC-54
SC-55
SC-56



Peak Demand (MW)
120,000
100,000
80,000
60,000
40,000
20,000
0
1
13
25
37
49
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73
85
97
109
121
133
145
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169
181
193
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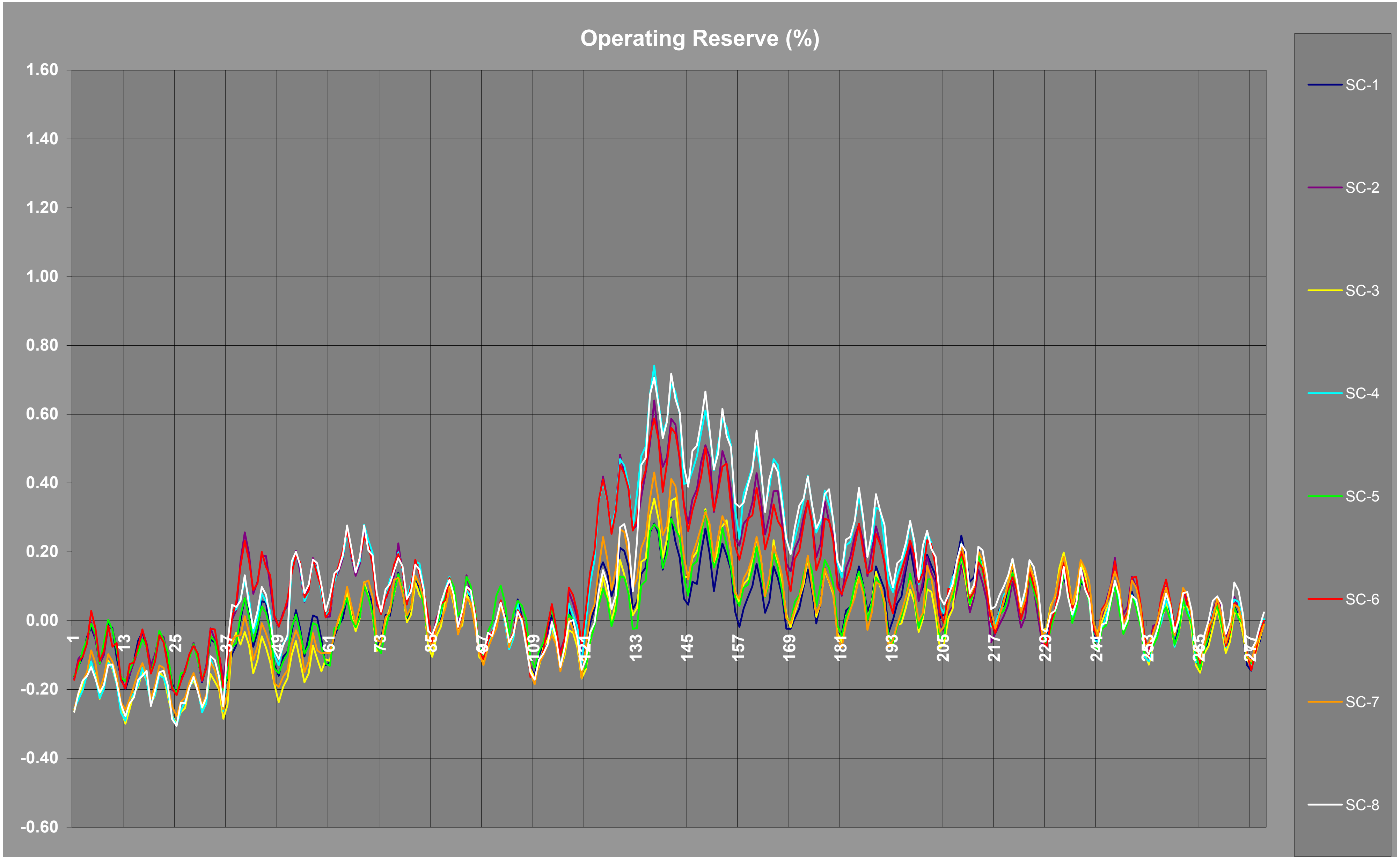
SC-64



Operating Reserve (%)
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
-0.60
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
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253
265
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SC-2
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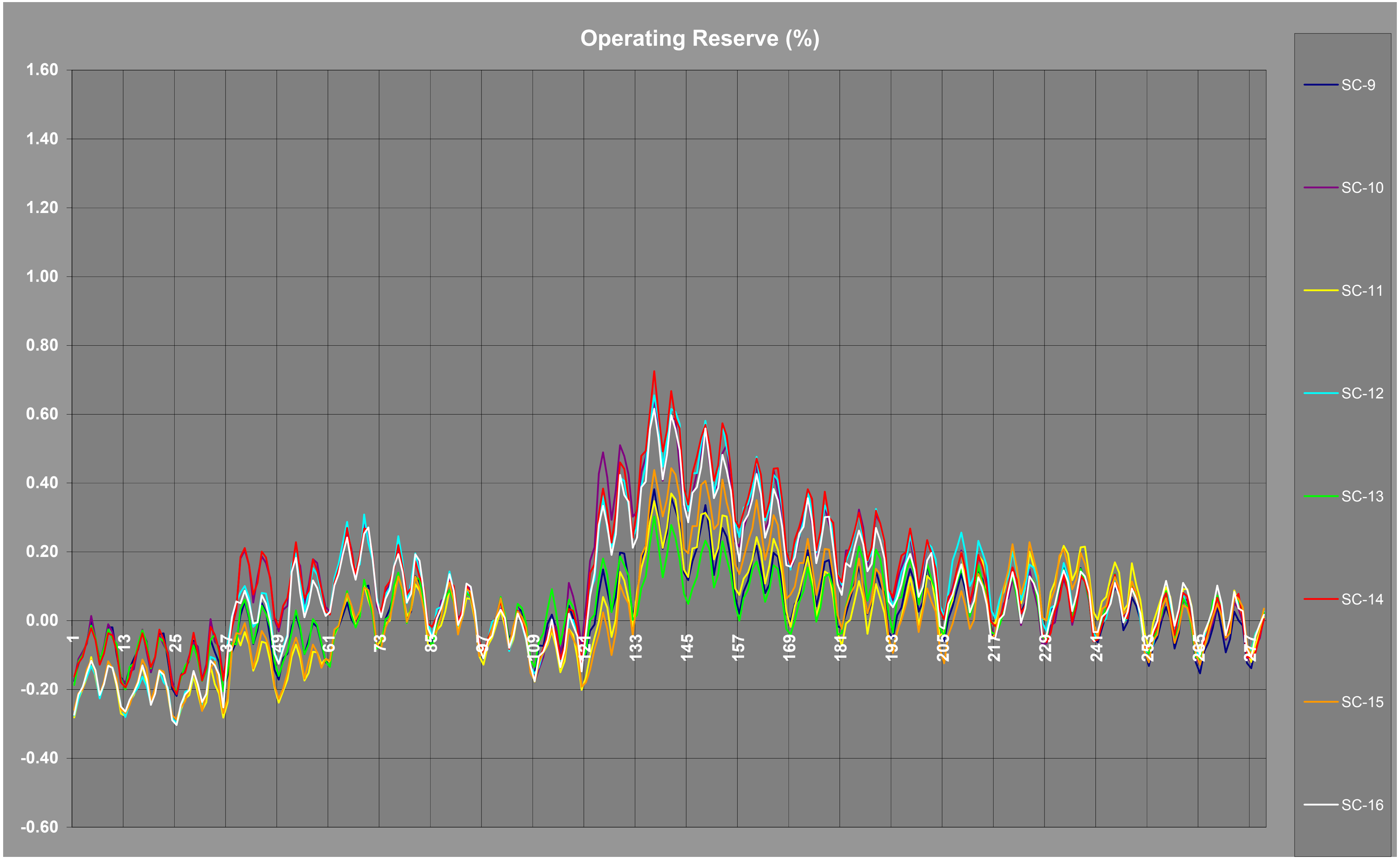
SC-8



Operating Reserve (%)
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
-0.60
1
13
25
37
49
61
73
85
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145
157
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181
193
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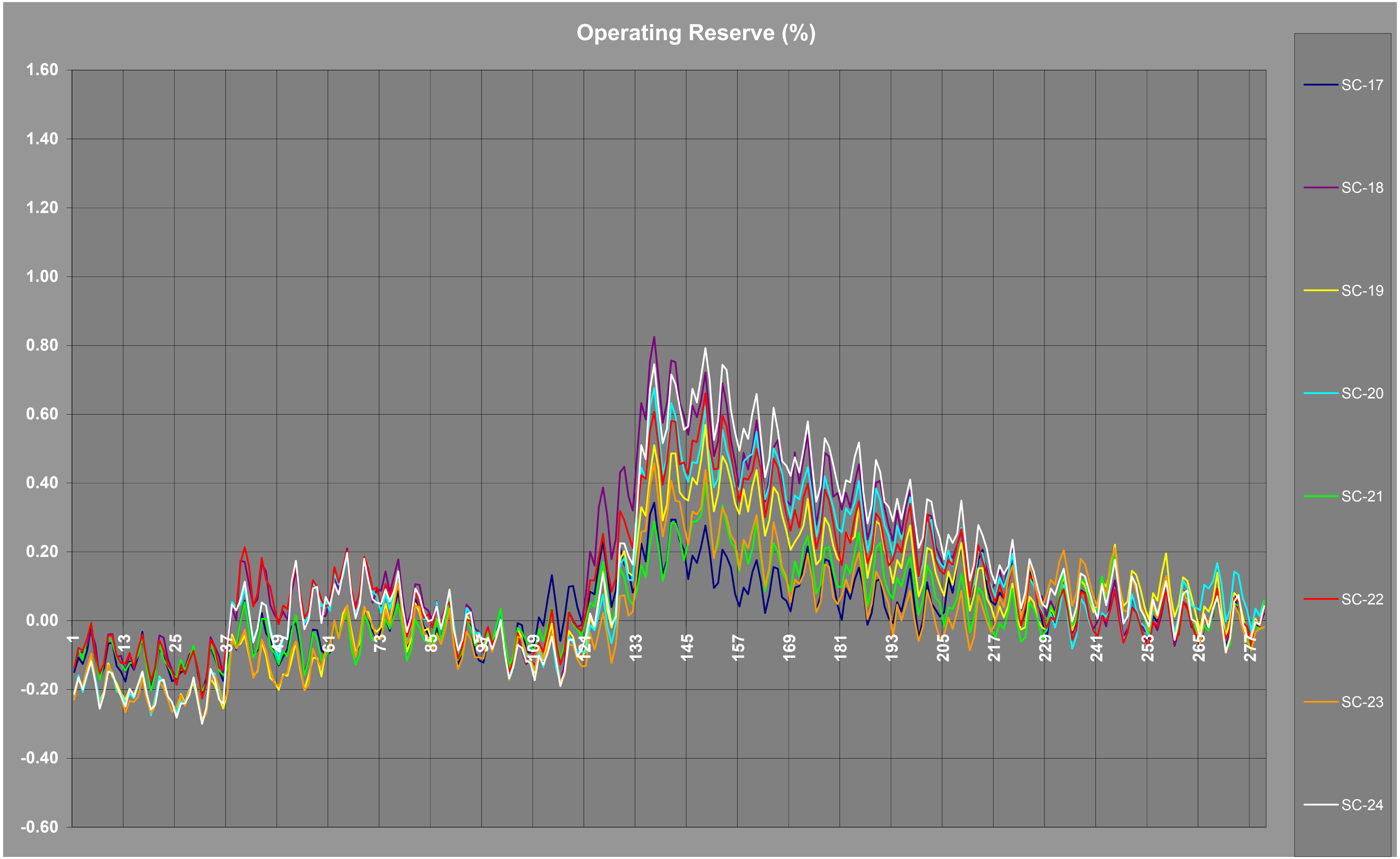
Operating Reserve (%)
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1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
-0.60
1
13
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181
193
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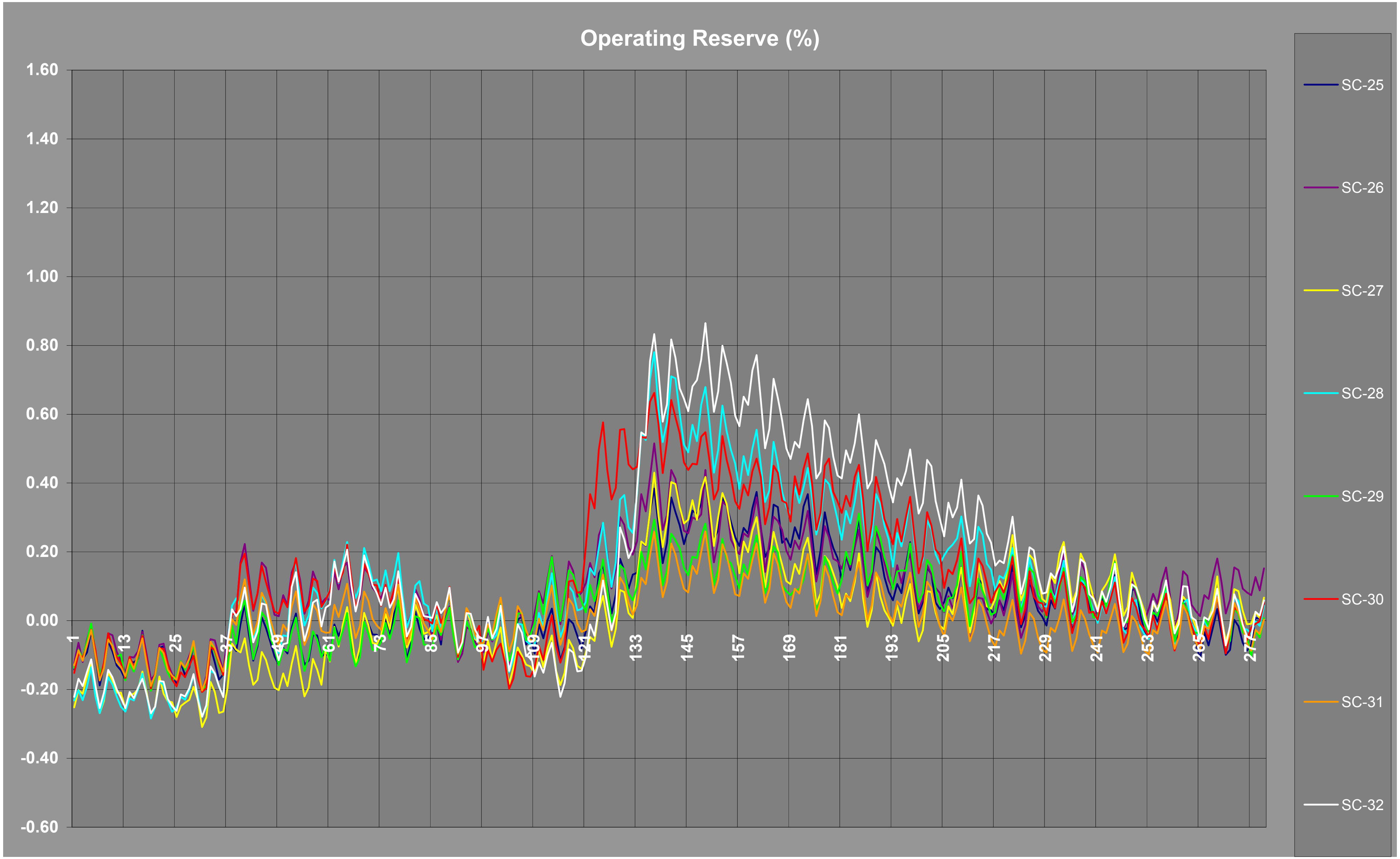
SC-24



Operating Reserve (%)
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
-0.60
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193
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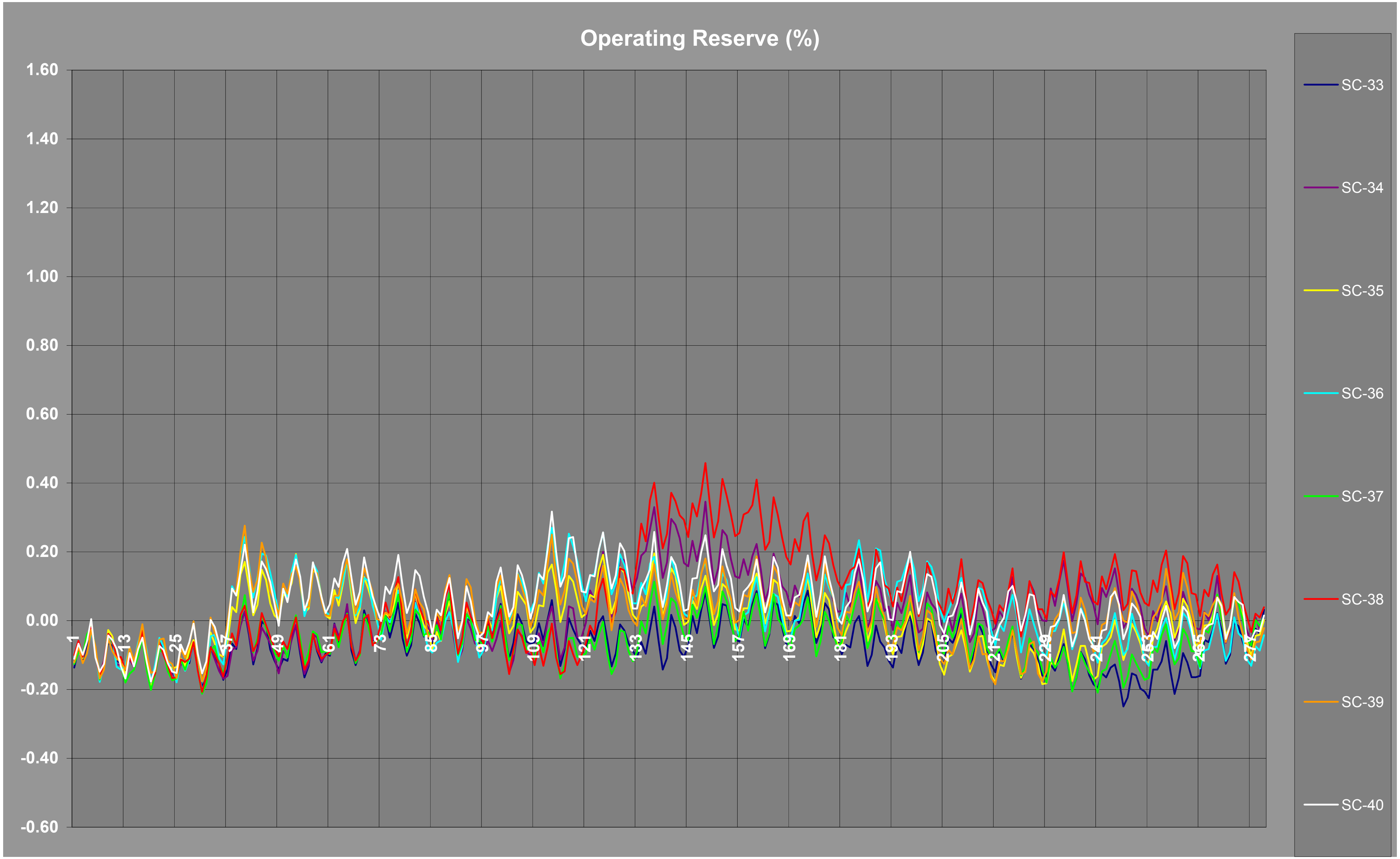

Operating Reserve (%)
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
-0.60
1
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25
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49
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181
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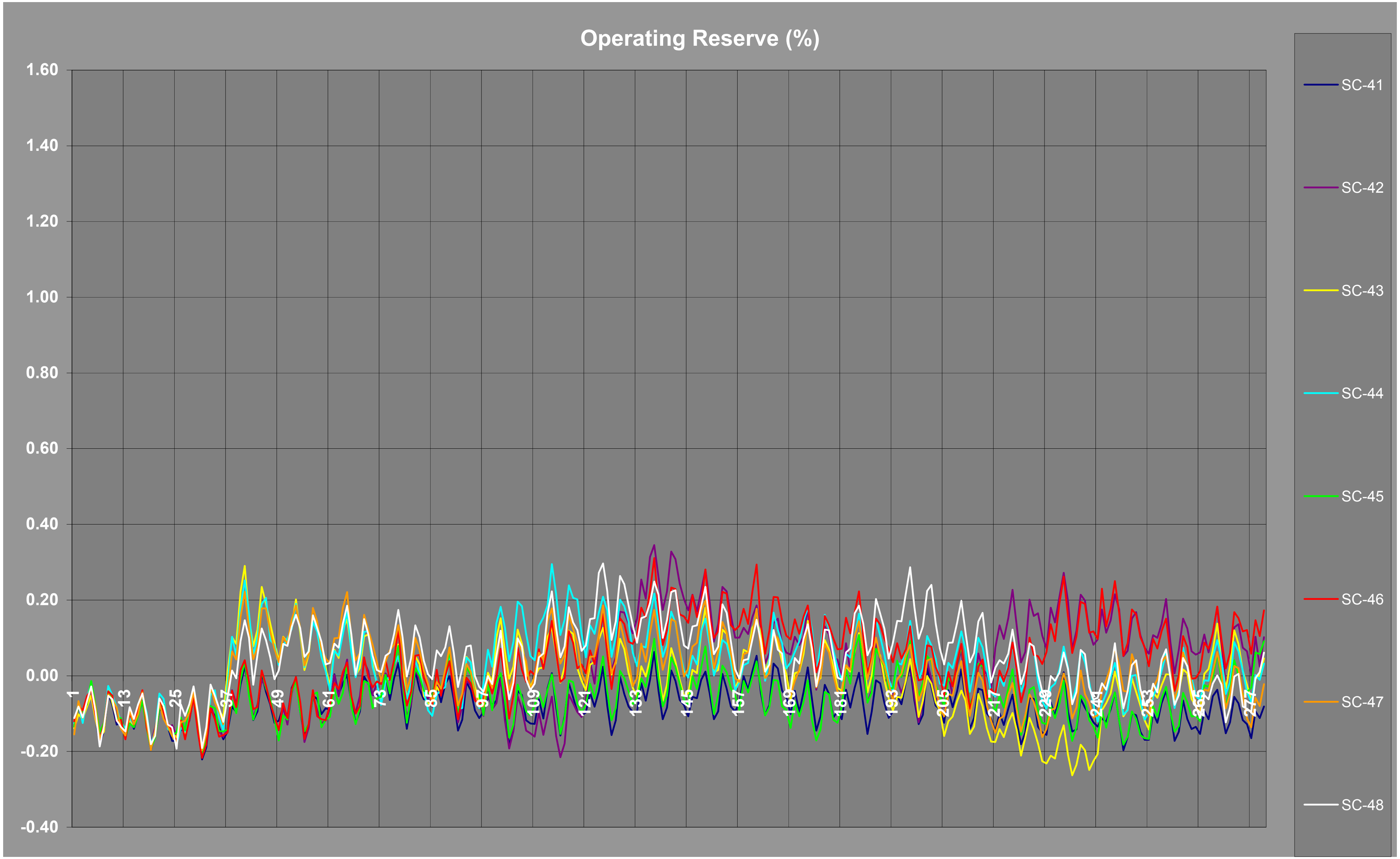
SC-40


Operating Reserve (%)
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1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
1
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181
193
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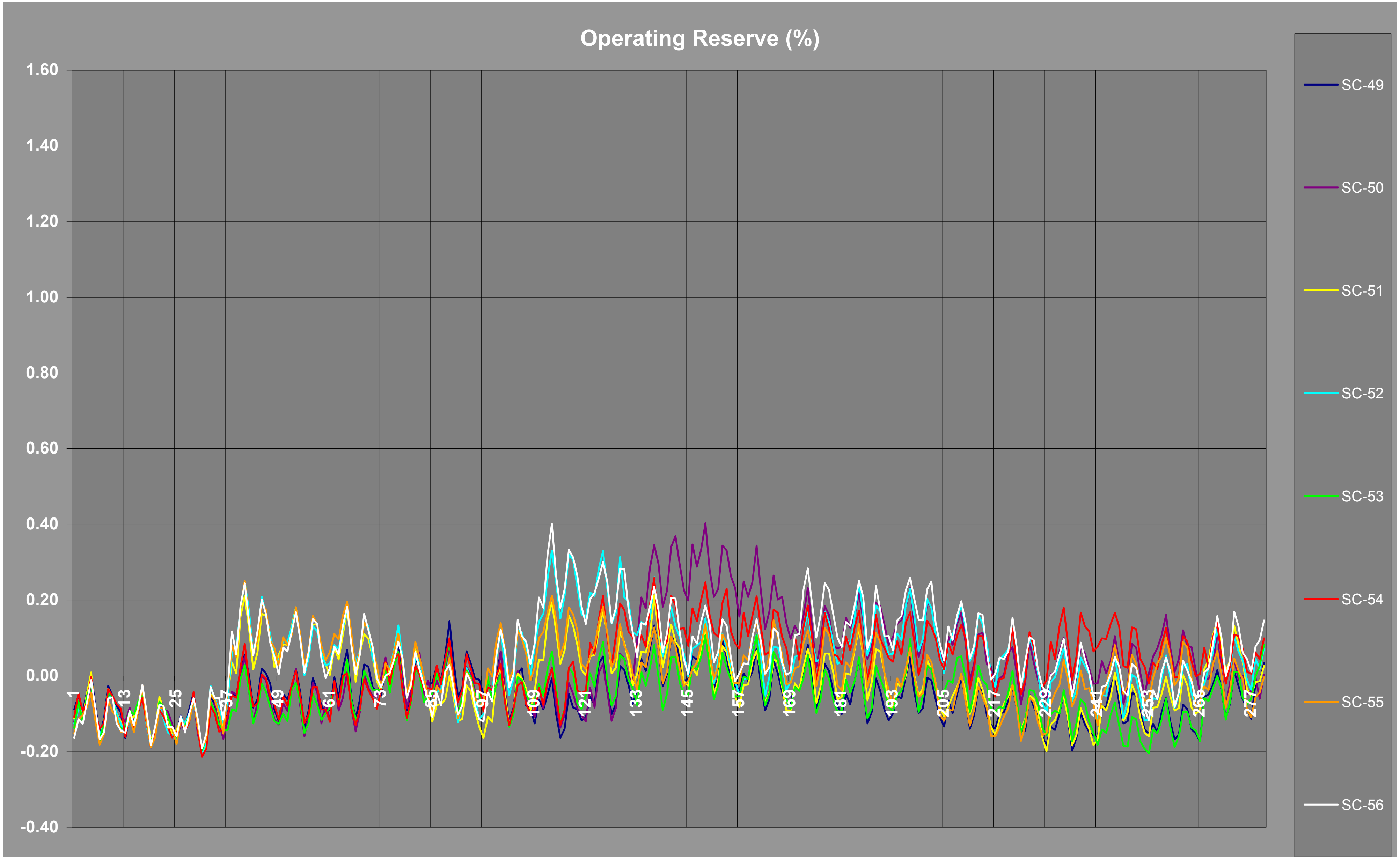

Operating Reserve (%)
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
1
13
25
37
49
61
73
85
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109
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133
145
157
169
181
193
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253
265
277
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SC-50
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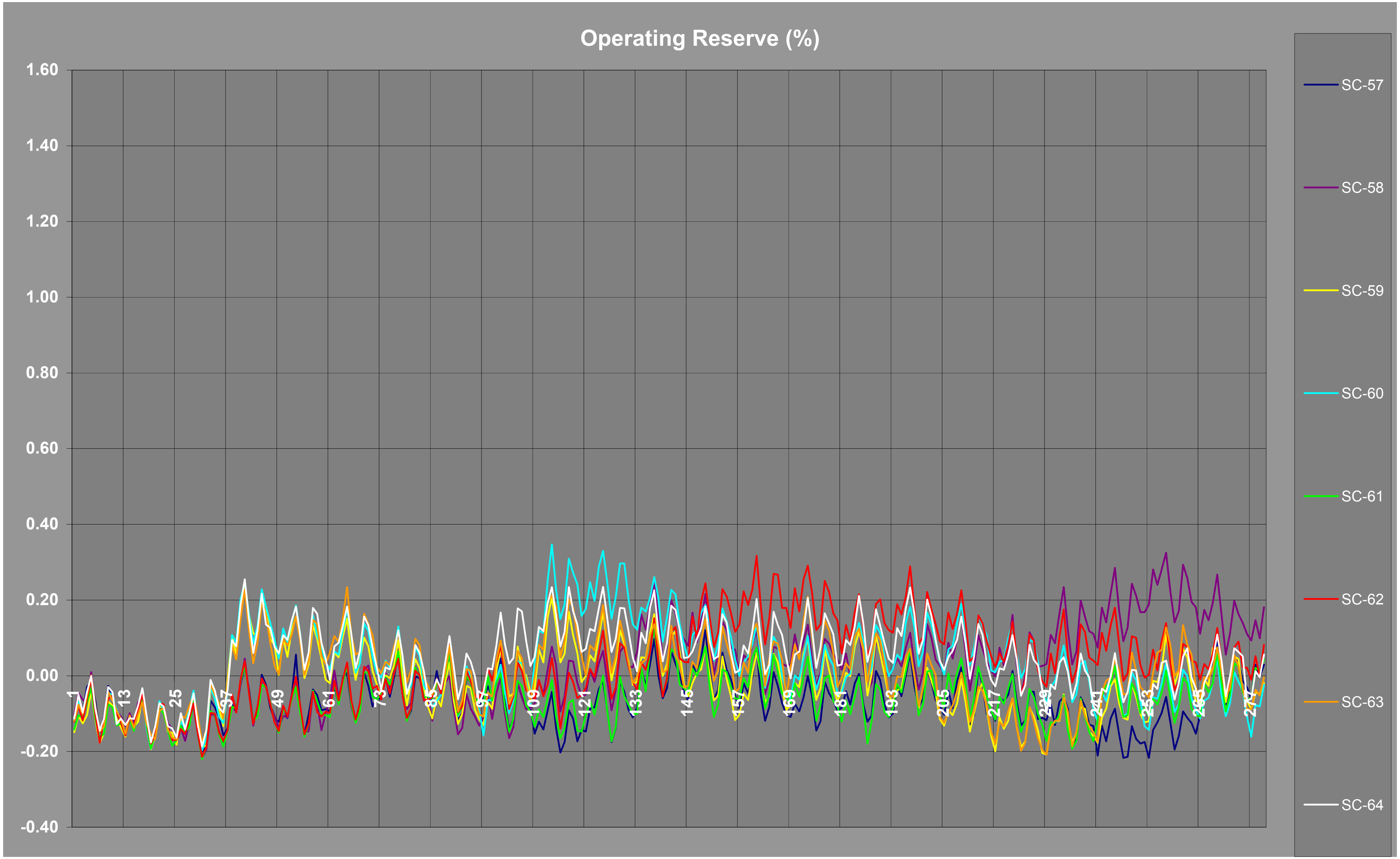
SC-53
SC-54
SC-55
SC-56



Operating Reserve (%)
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
-0.20
-0.40
1
13
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145
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181
193
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SC-57
SC-58
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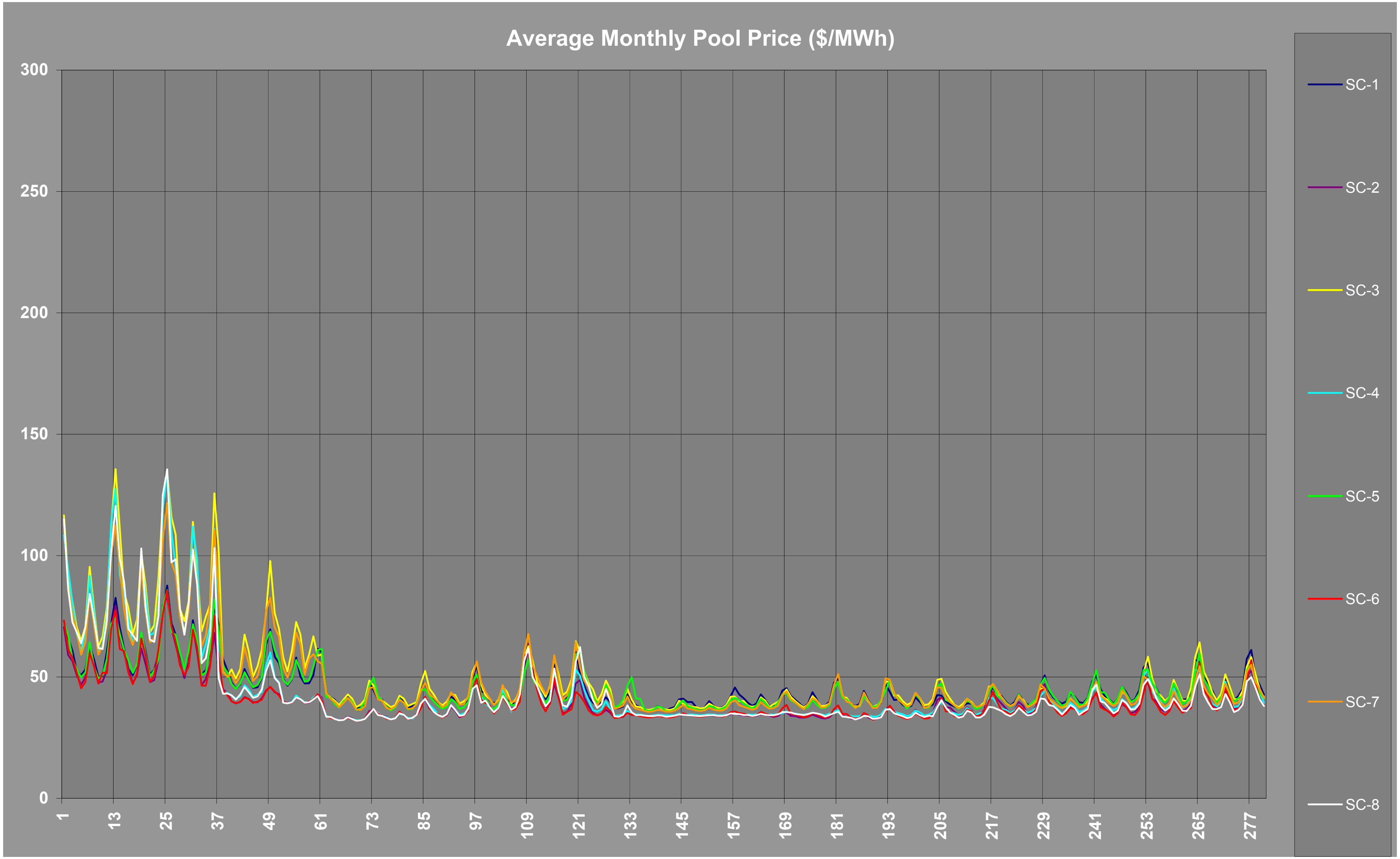
SC-60
SC-61
SC-62
SC-63
SC-64



Average Monthly Pool Price ($/MWh)
300
250
200
150
100
50
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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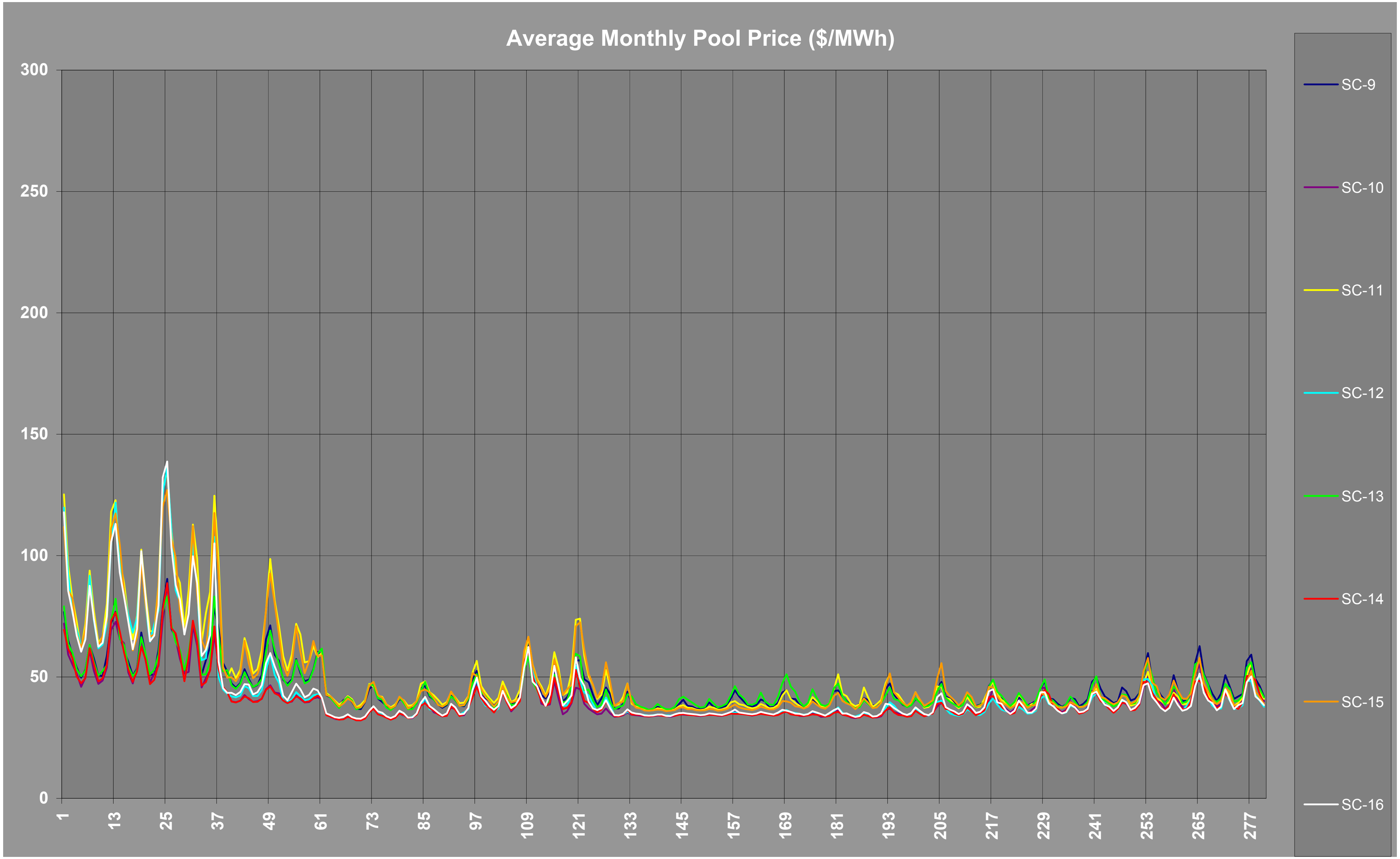
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8


Average Monthly Pool Price ($/MWh)
300
250
200
150
100
50
0
1
13
25
37
49
61
73
85
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121
133
145
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169
181
193
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265
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SC-14
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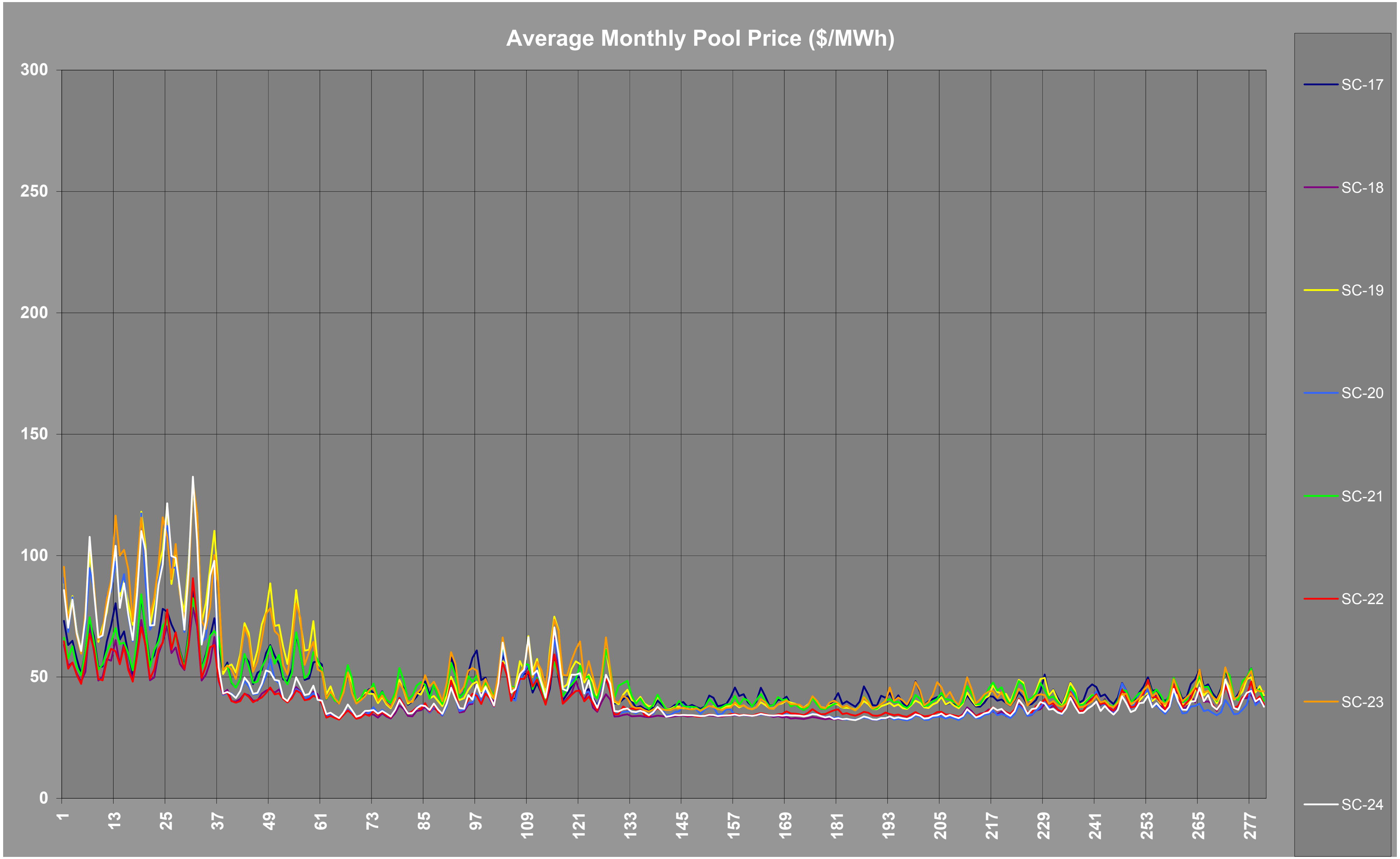
SC-16


Average Monthly Pool Price ($/MWh)
300
250
200
150
100
50
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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253
265
277
SC-17
SC-18
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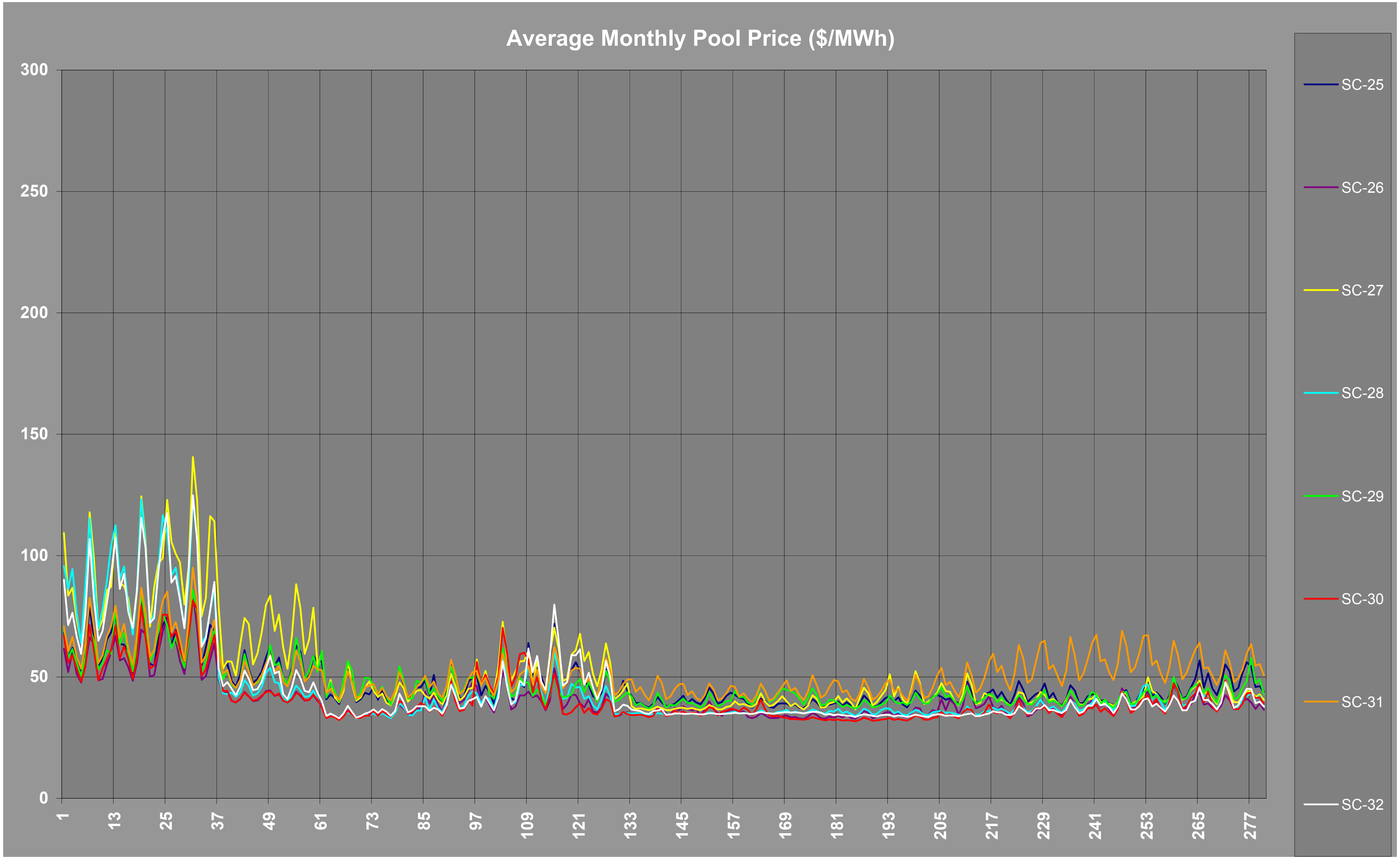
SC-20
SC-21
SC-22
SC-23
SC-24


Average Monthly Pool Price ($/MWh)
300
250
200
150
100
50
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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265
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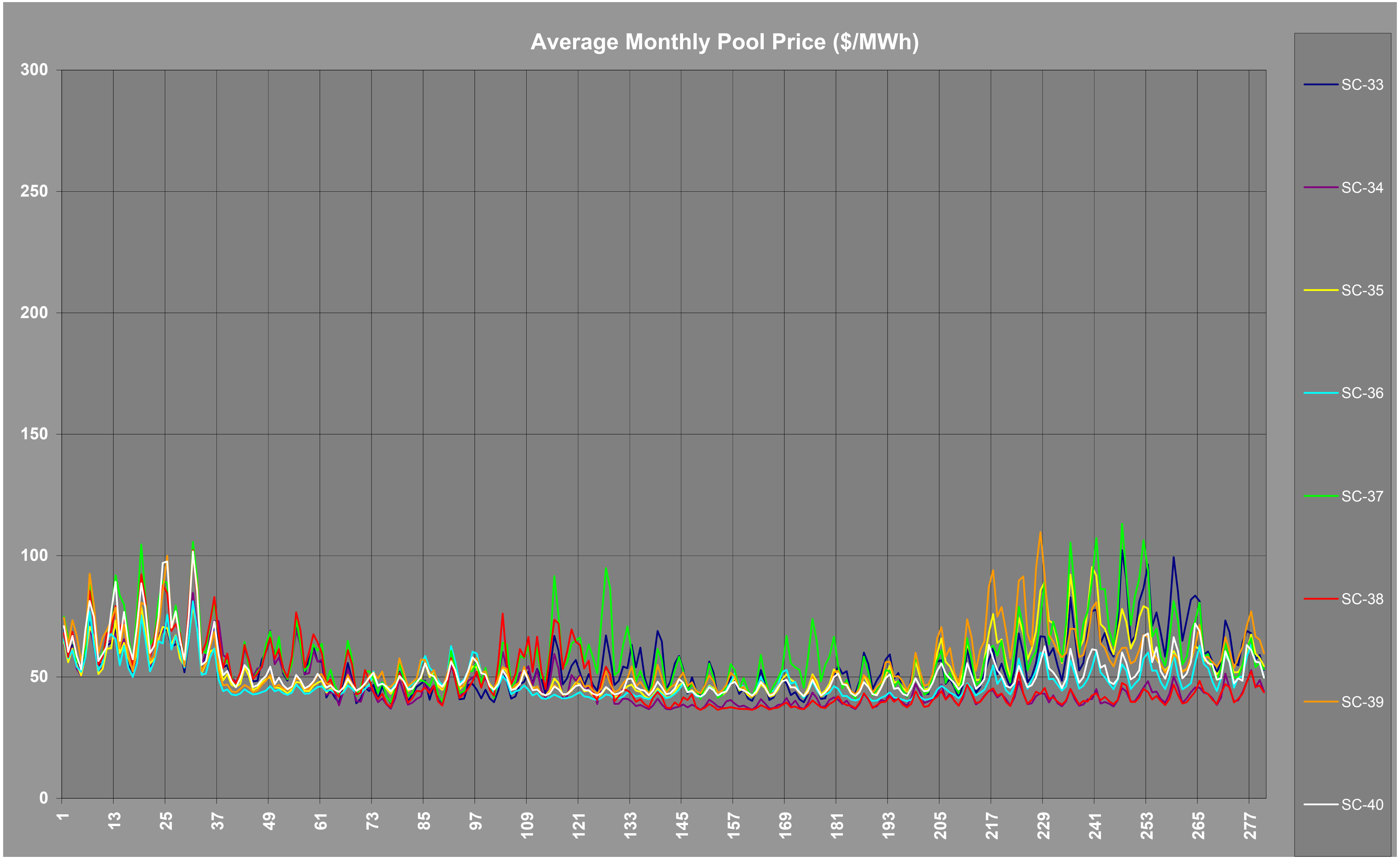
SC-32



Average Monthly Pool Price ($/MWh)
300
250
200
150
100
50
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
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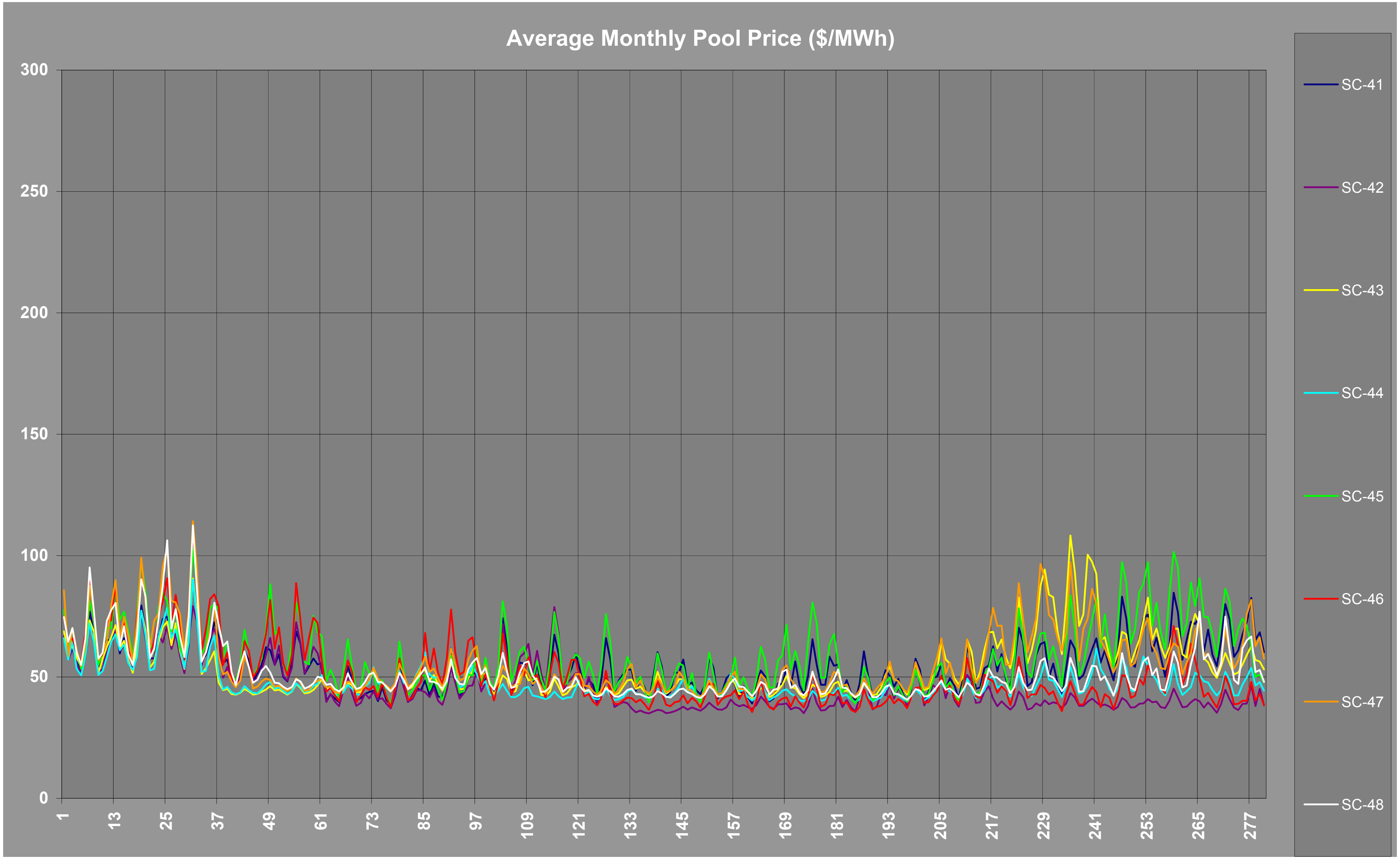
SC-40


Average Monthly Pool Price ($/MWh)
300
250
200
150
100
50
0
1
13
25
37
49
61
73
85
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109
121
133
145
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169
181
193
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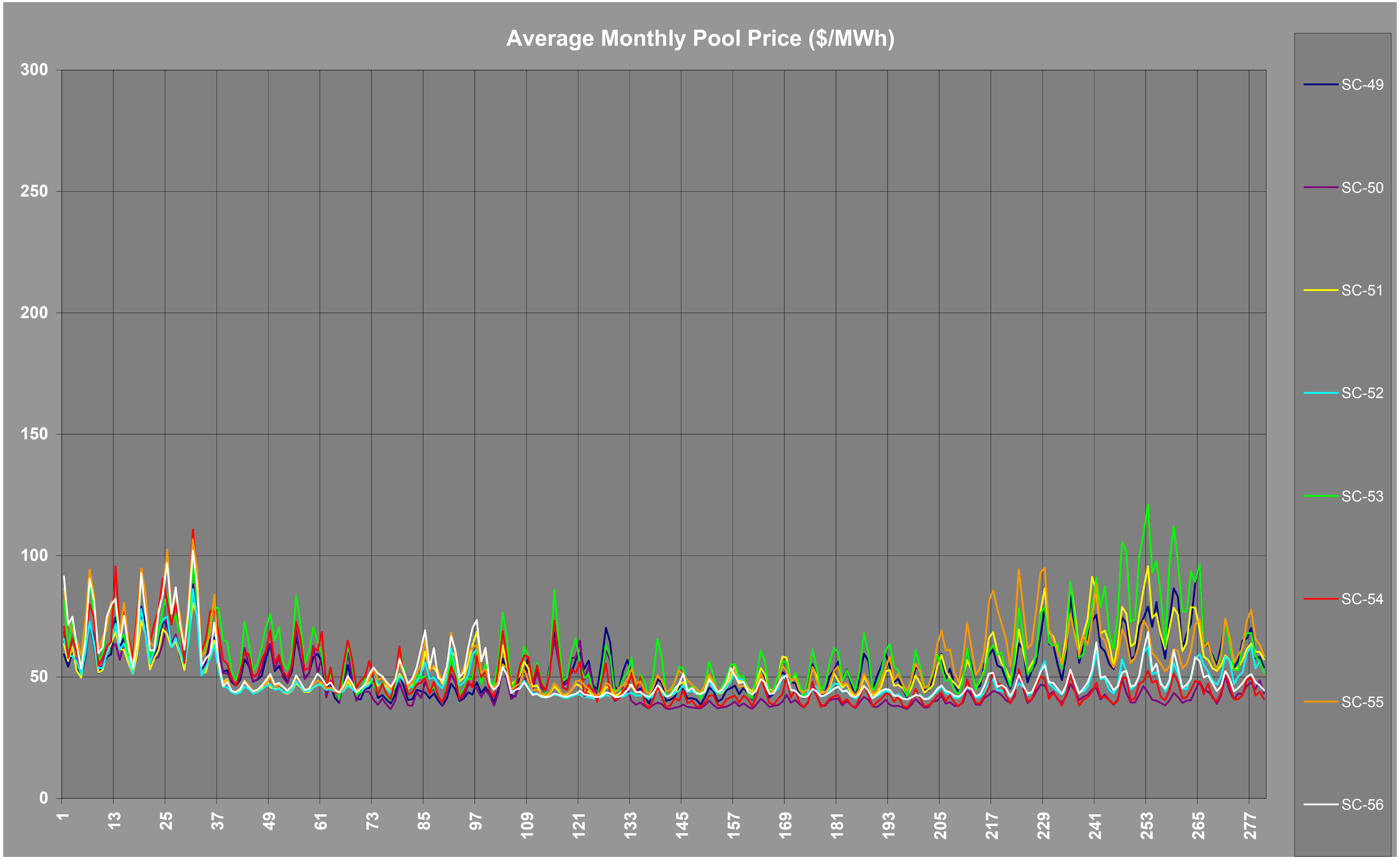
SC-48



Average Monthly Pool Price ($/MWh)
300
250
200
150
100
50
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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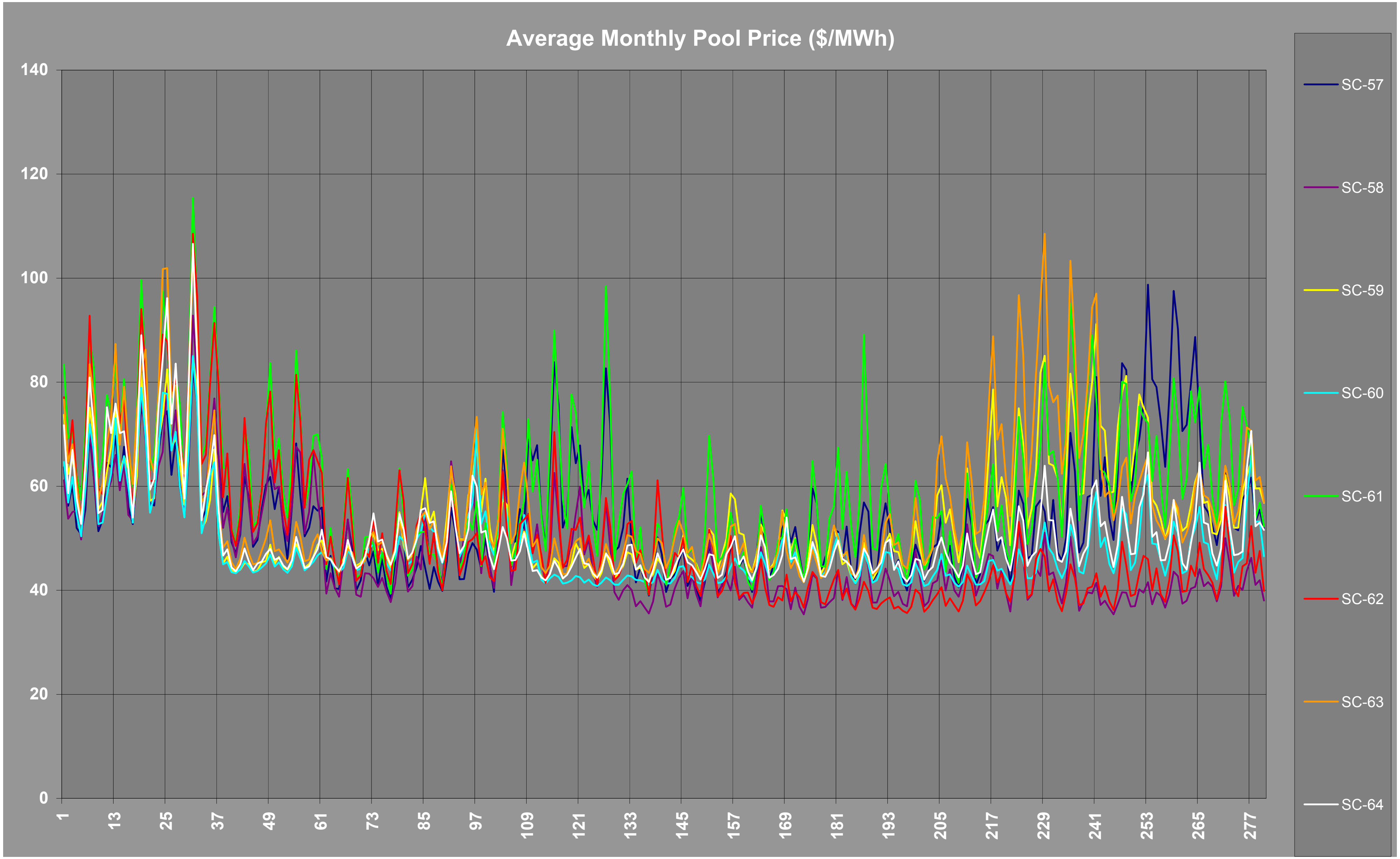
SC-56



Average Monthly Pool Price ($/MWh)
140
120
100
80
60
40
20
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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265
277
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SC-58
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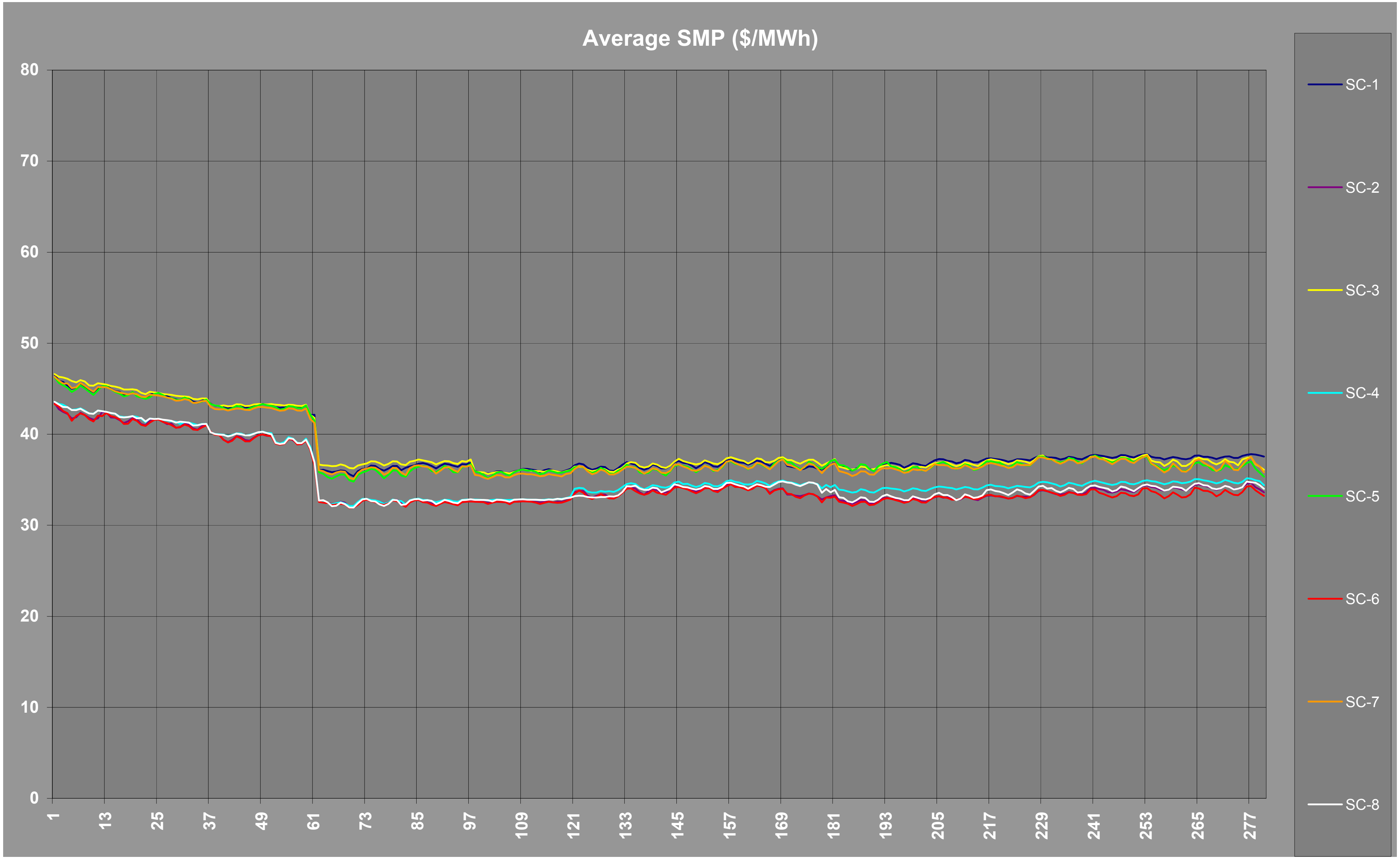
SC-64


Average SMP ($/MWh)
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
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97
109
121
133
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169
181
193
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253
265
277
SC-1
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SC-4
SC-5
SC-6
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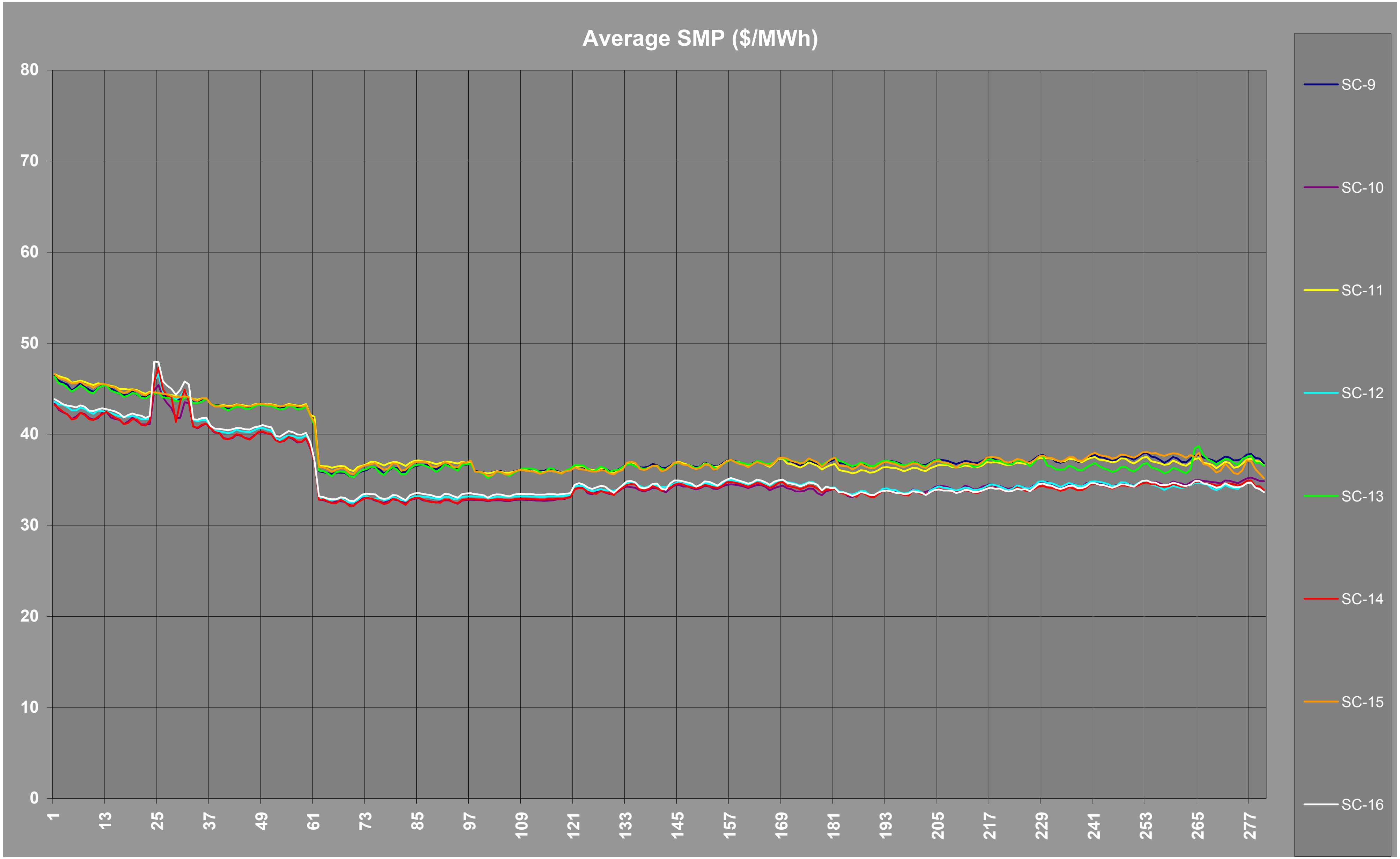
SC-8


Average SMP ($/MWh)
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
85
97
109
121
133
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169
181
193
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277
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SC-14
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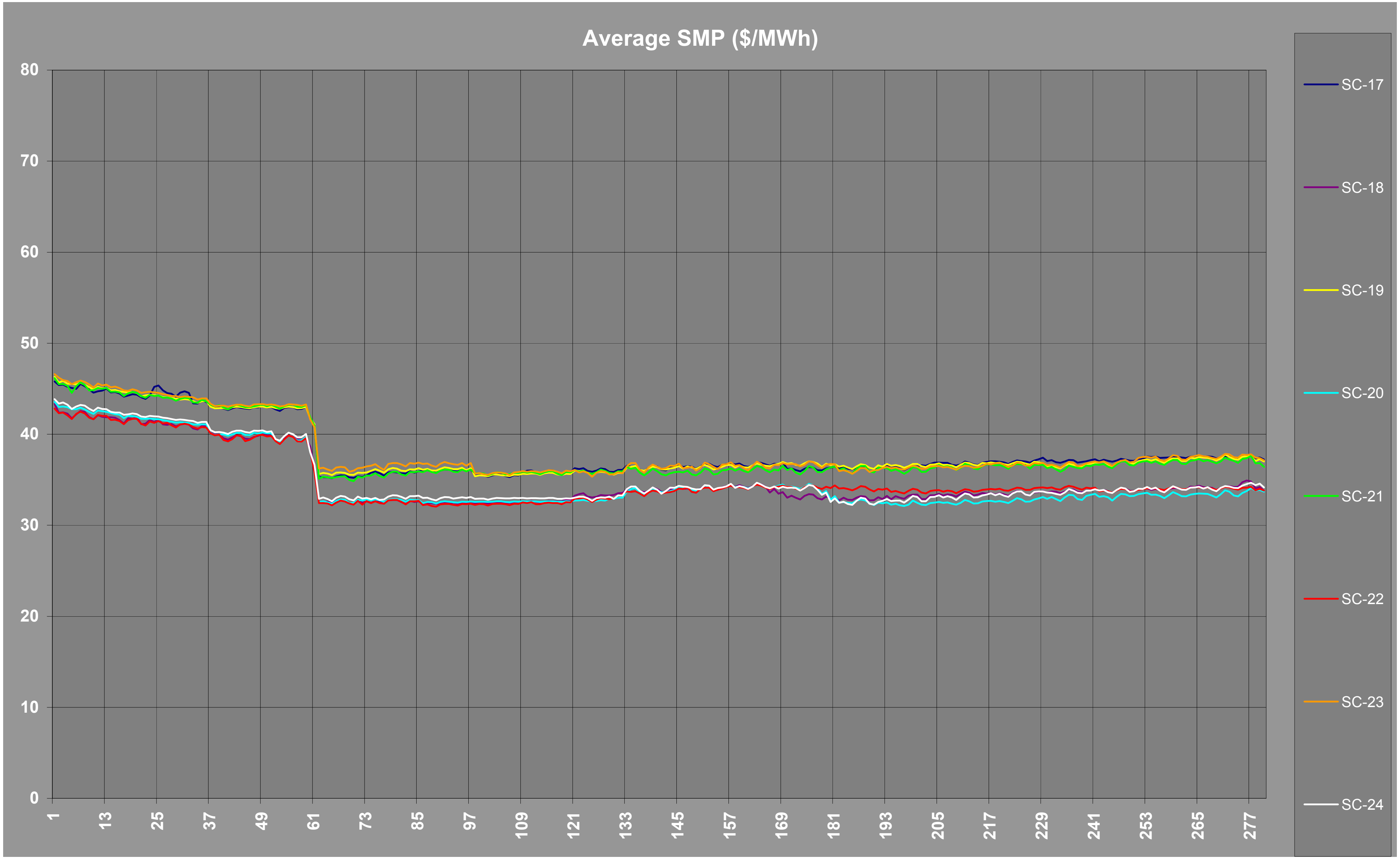
SC-16



Average SMP ($/MWh)
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
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97
109
121
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169
181
193
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265
277
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SC-18
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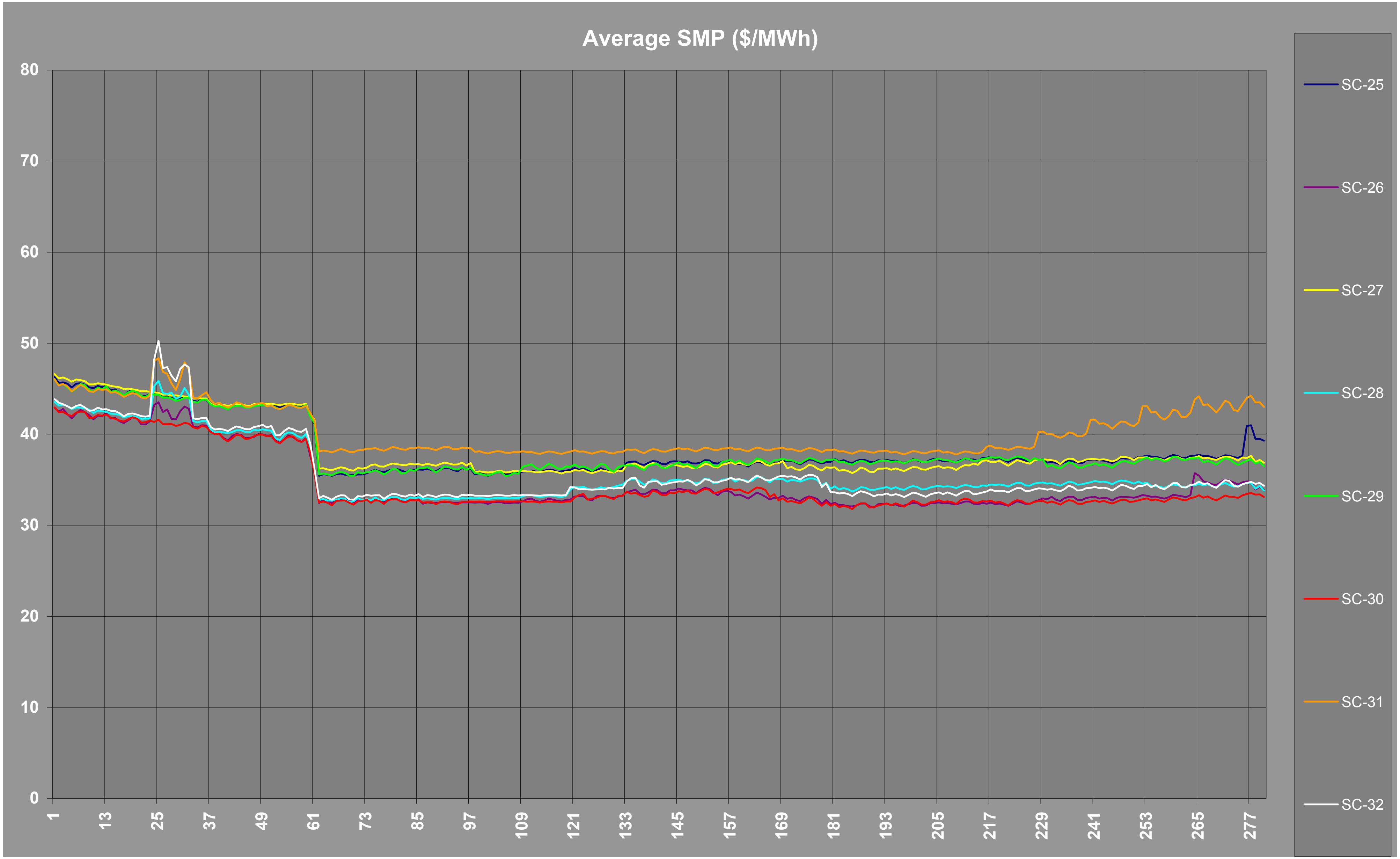
SC-21
SC-22
SC-23
SC-24



Average SMP ($/MWh)
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
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97
109
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181
193
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277
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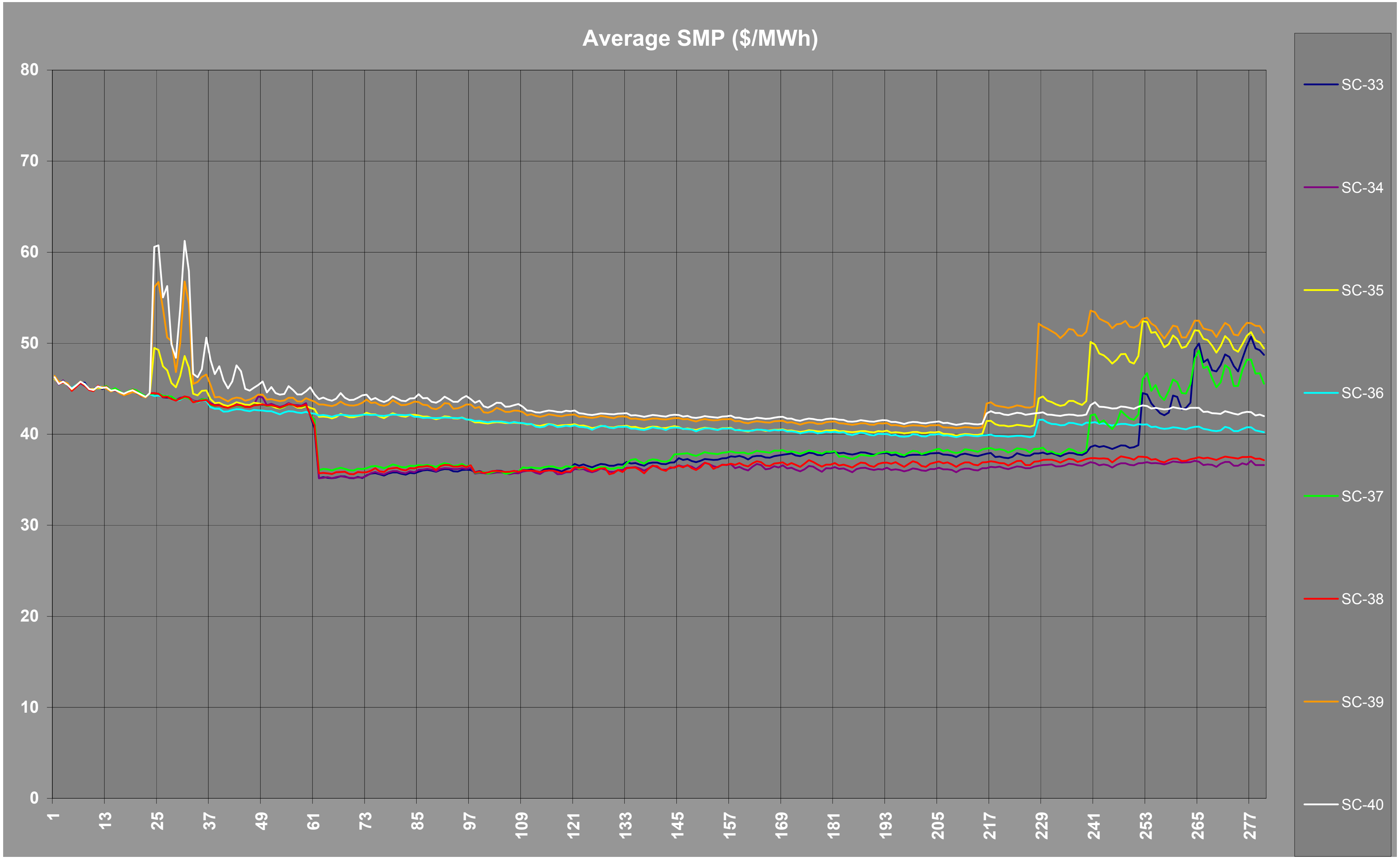
SC-32


Average SMP ($/MWh)
80
70
60
50
40
30
20
10
0
1
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37
49
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73
85
97
109
121
133
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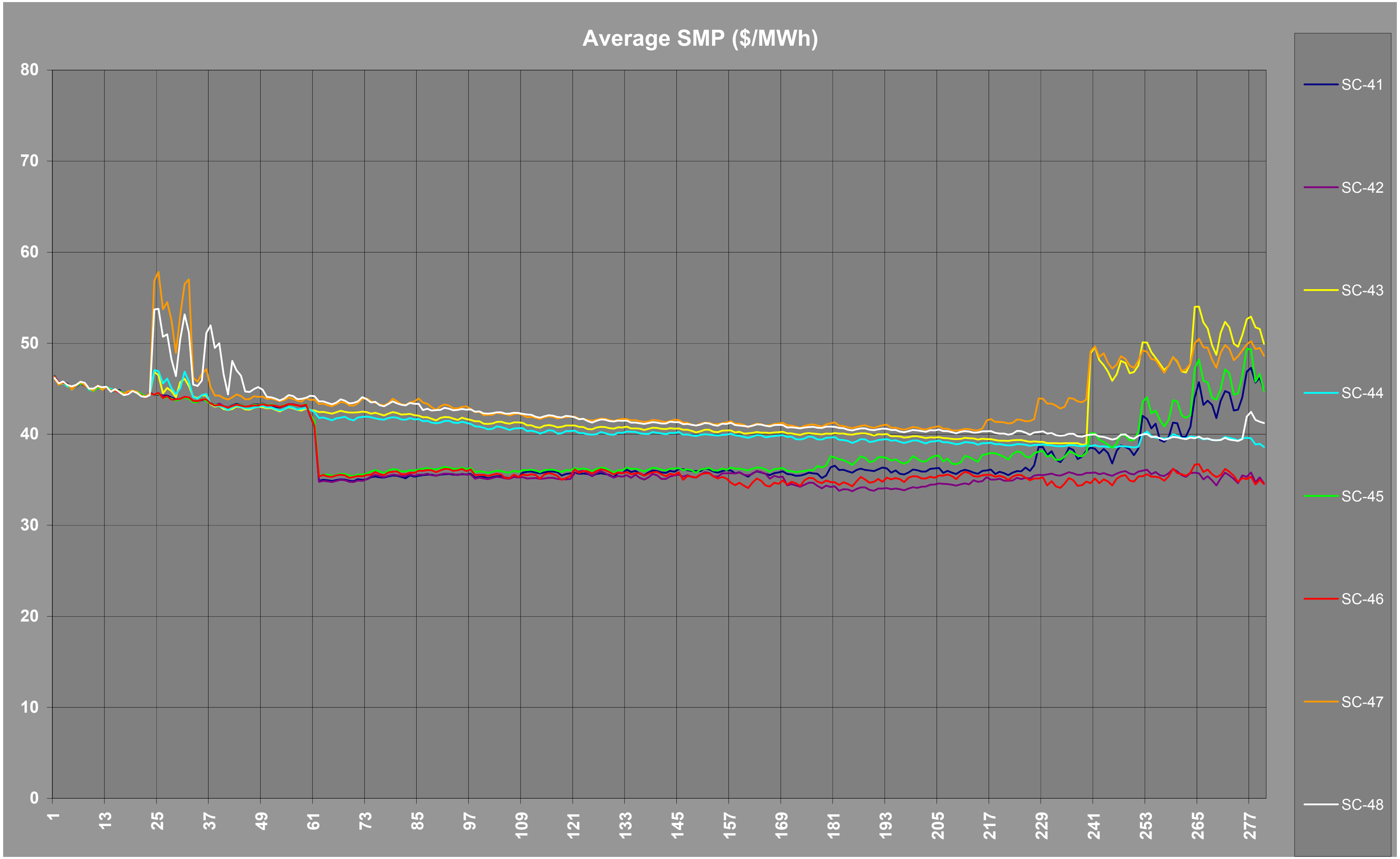
SC-40


Average SMP ($/MWh)
80
70
60
50
40
30
20
10
0
1
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25
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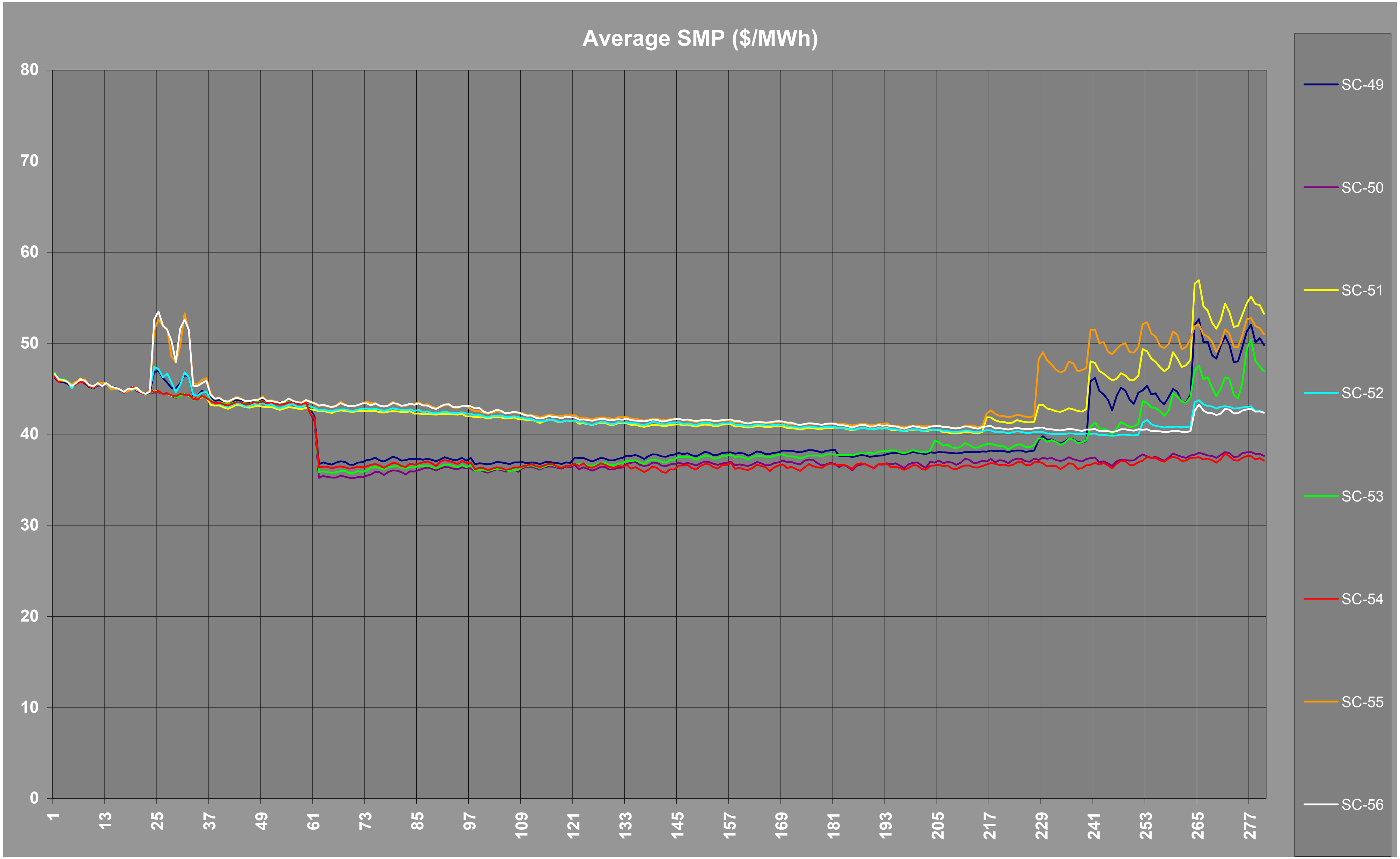
SC-48



Average SMP ($/MWh)
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
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97
109
121
133
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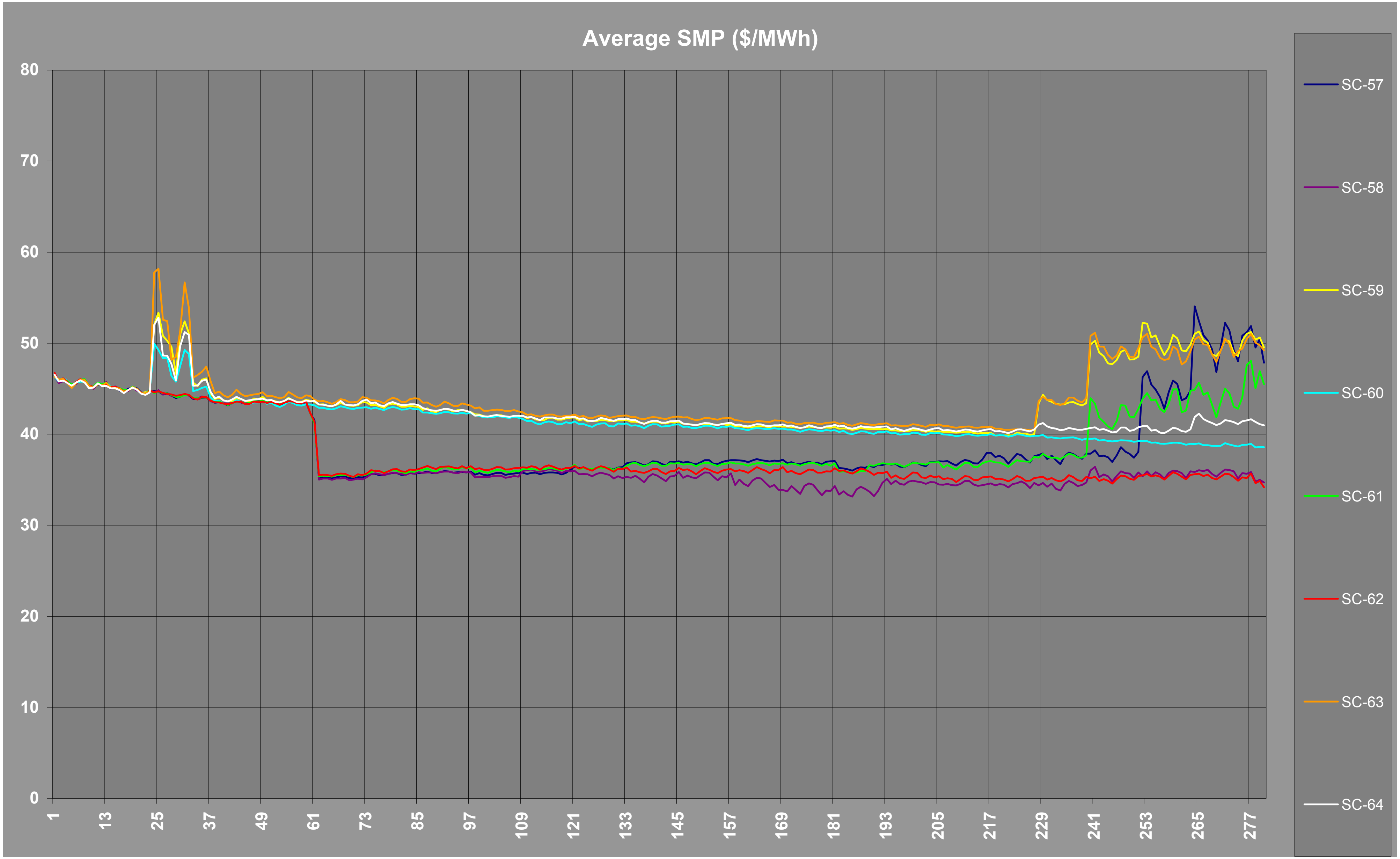
SC-54
SC-55
SC-56



Average SMP ($/MWh)
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
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97
109
121
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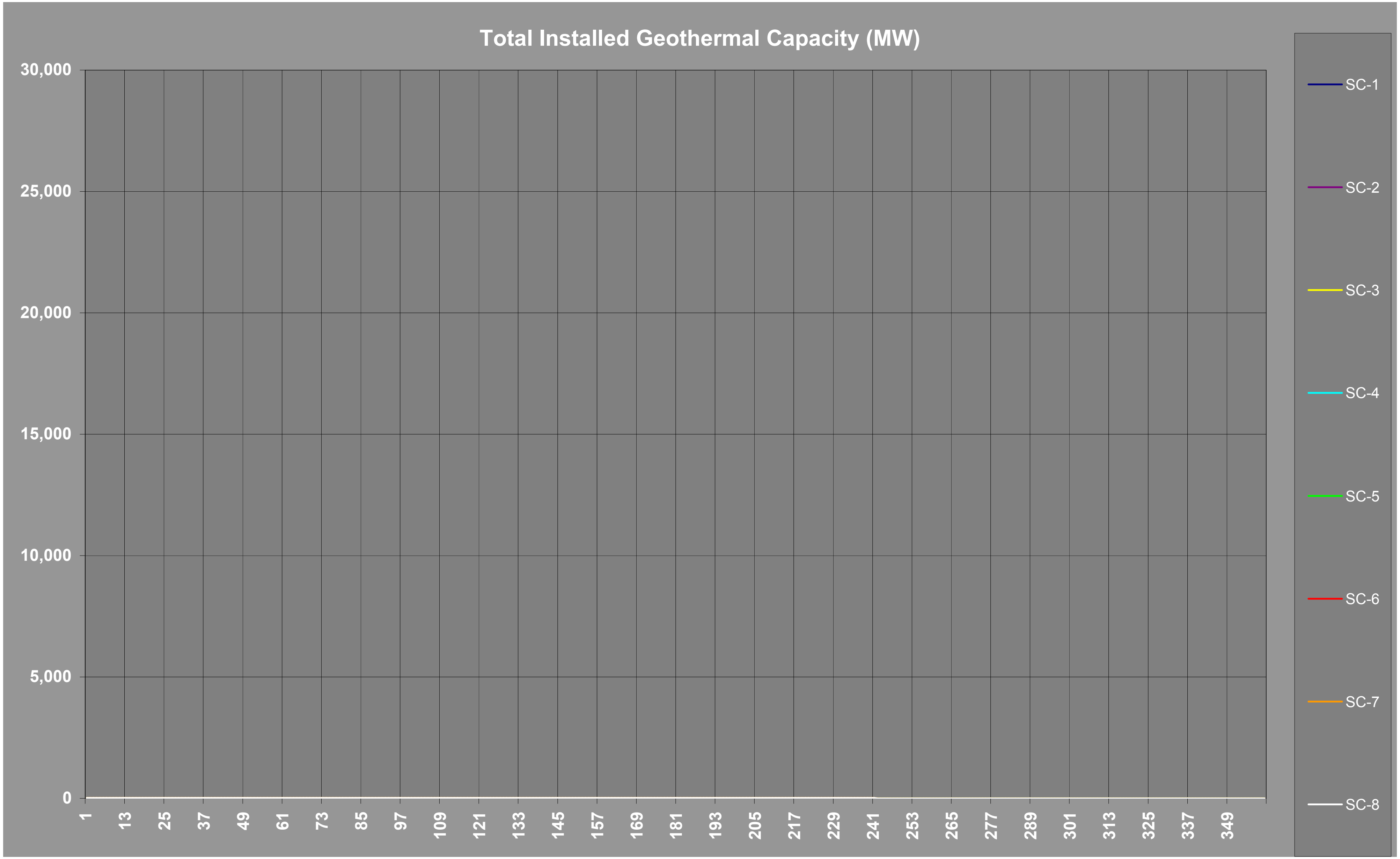
SC-64


Total Installed Geothermal Capacity (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
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325
337
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SC-1
SC-2
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SC-6
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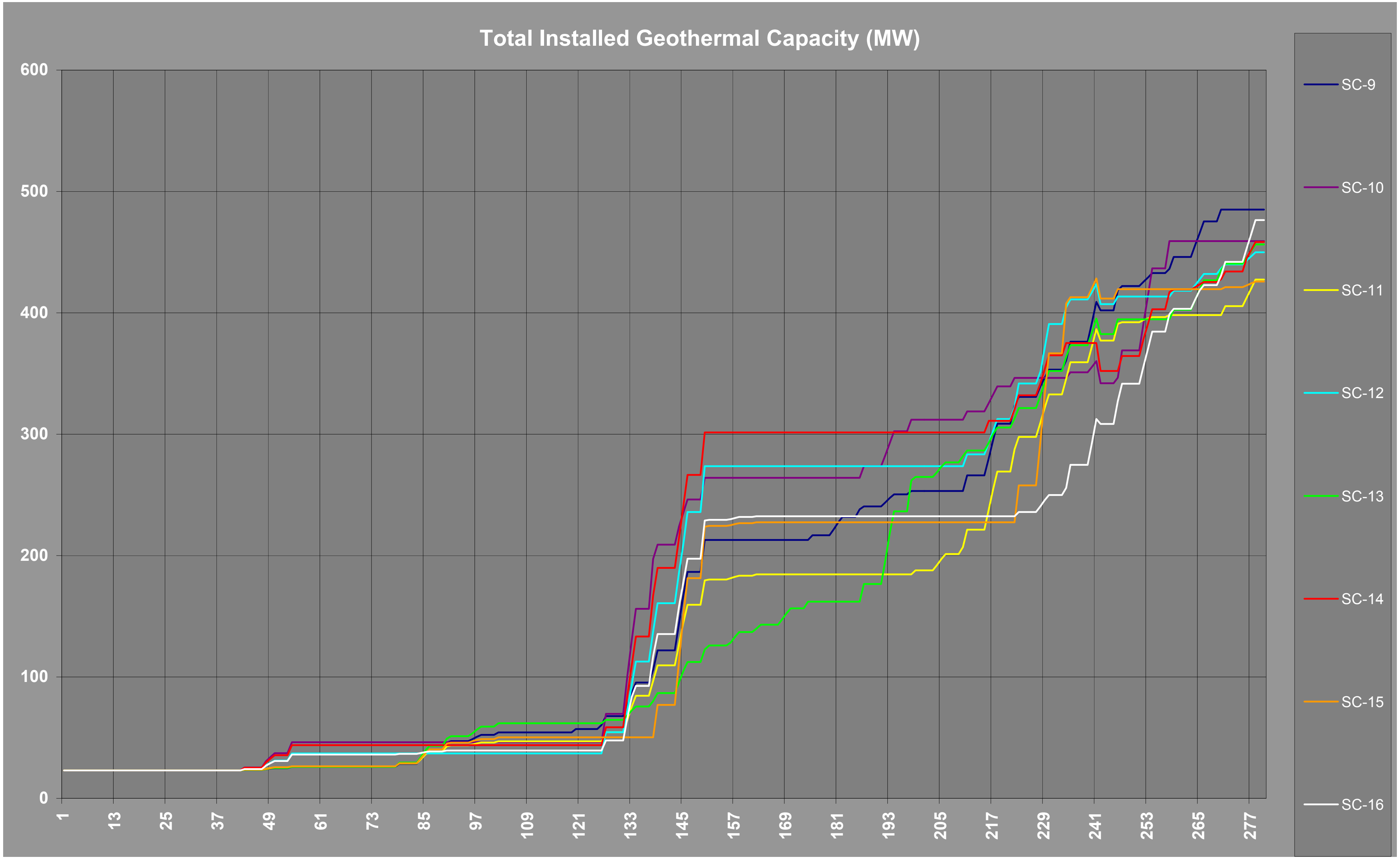
SC-8


Total Installed Geothermal Capacity (MW)
600
500
400
300
200
100
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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253
265
277
SC-9
SC-10
SC-11
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SC-14
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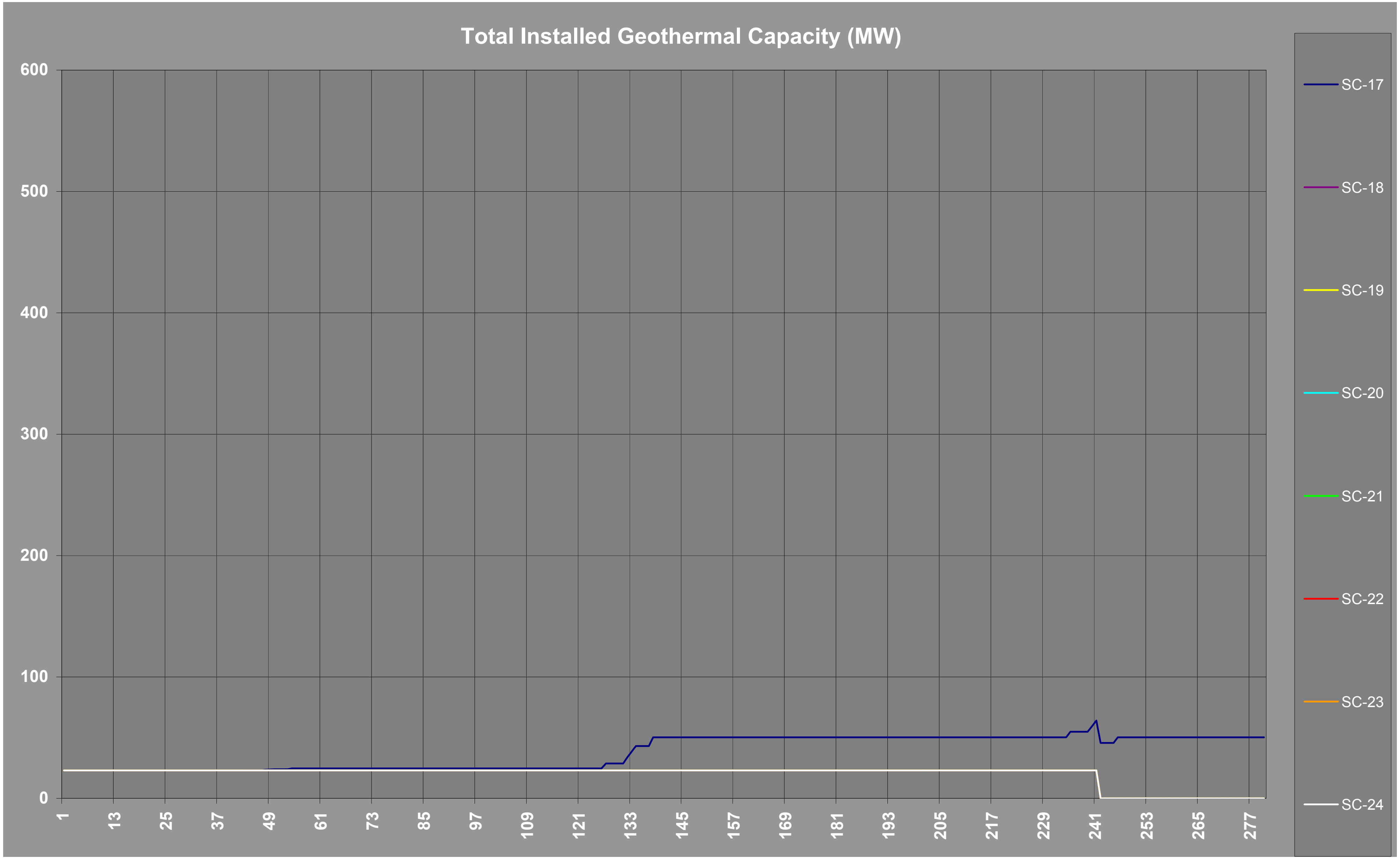
SC-16


Total Installed Geothermal Capacity (MW)
600
500
400
300
200
100
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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265
277
SC-17
SC-18
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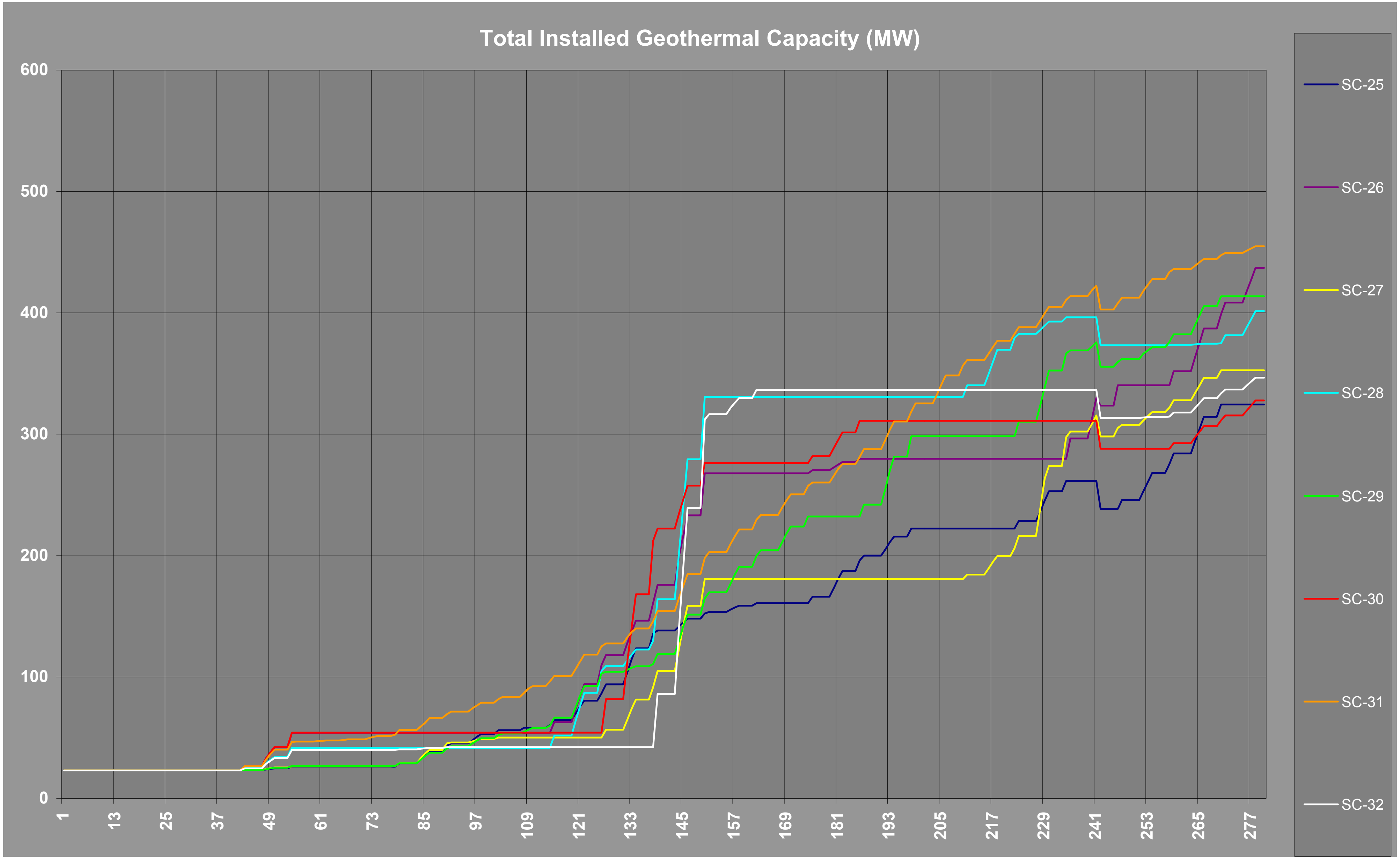
SC-24



Total Installed Geothermal Capacity (MW)
600
500
400
300
200
100
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
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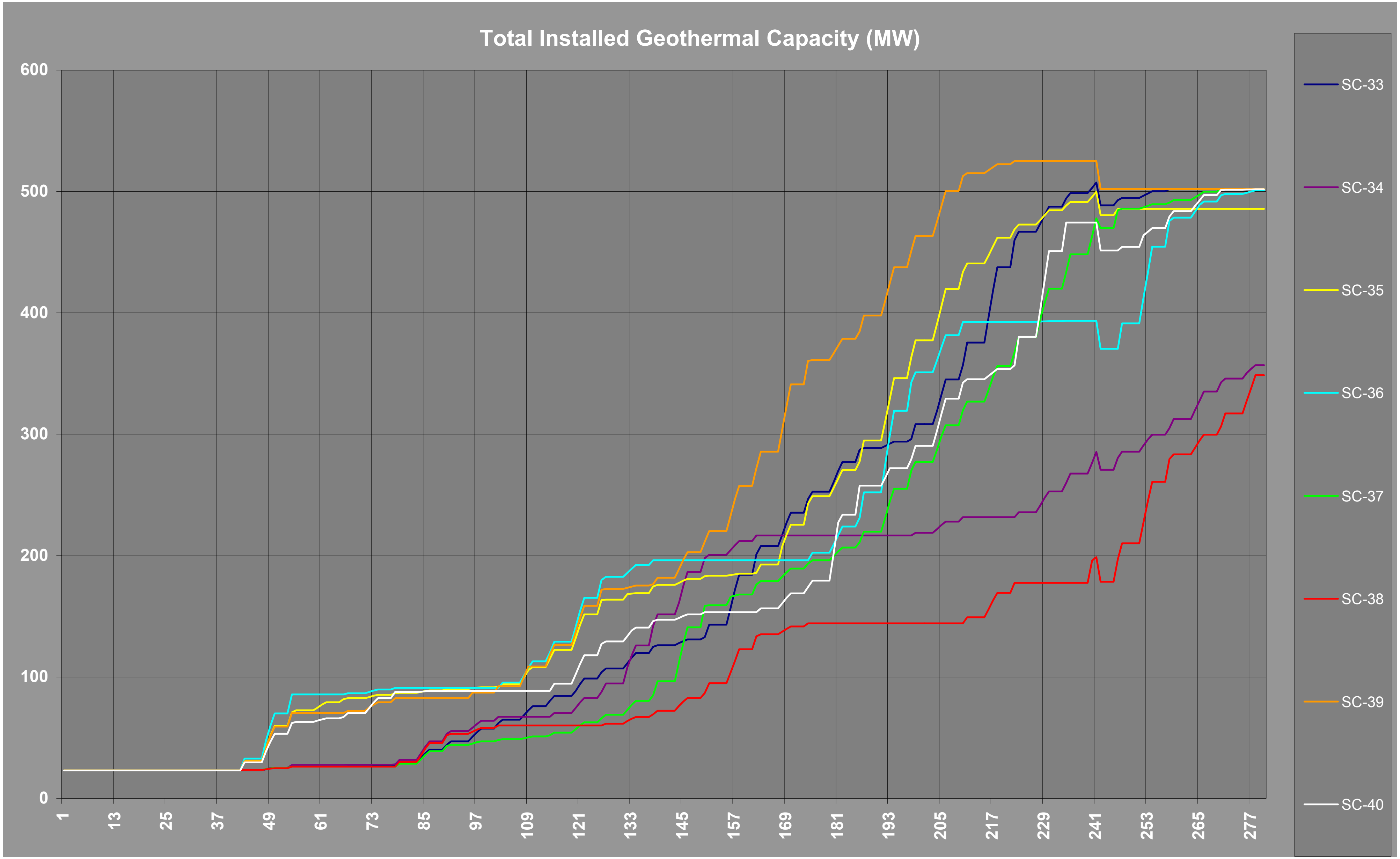
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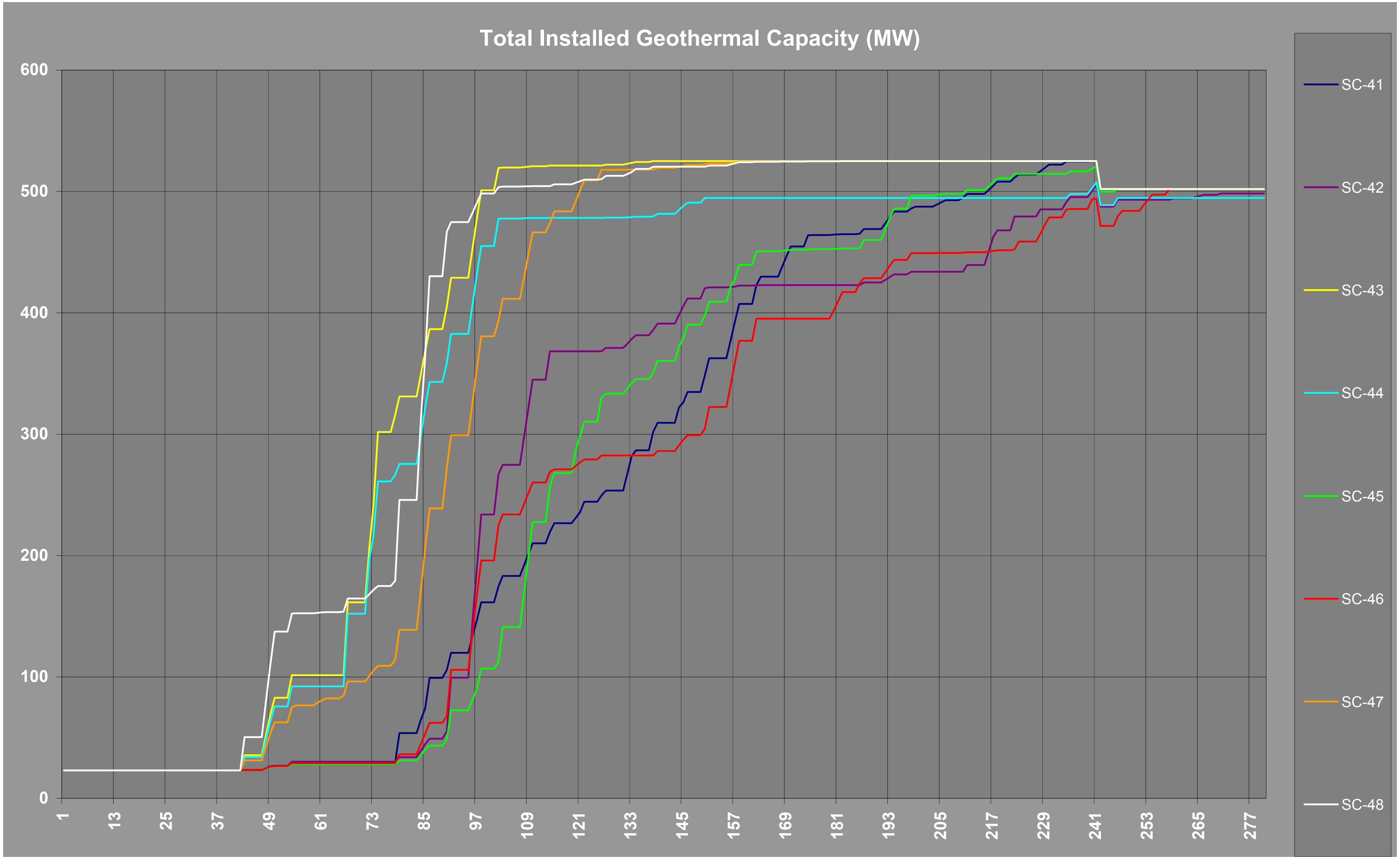

Total Installed Geothermal Capacity (MW)
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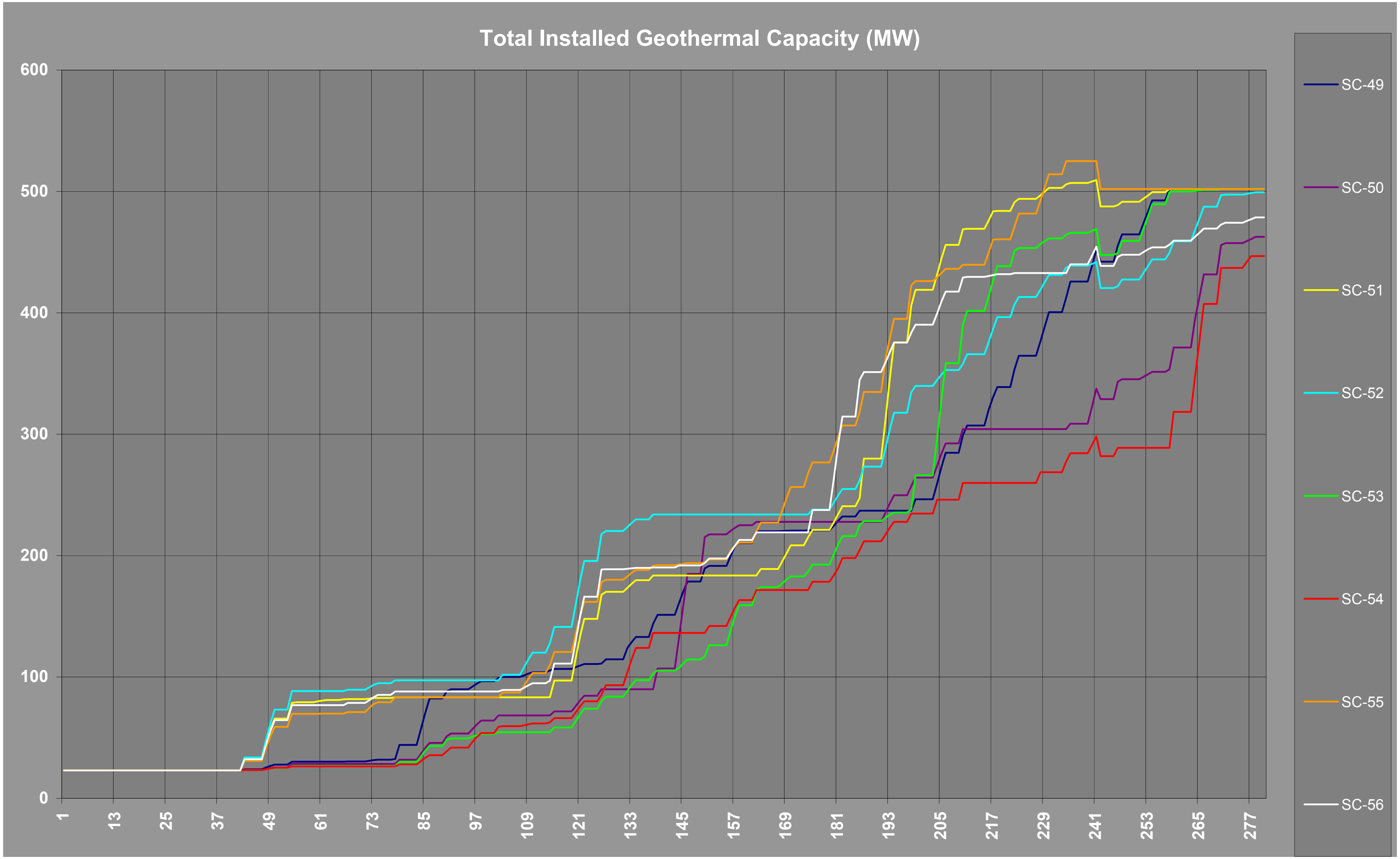
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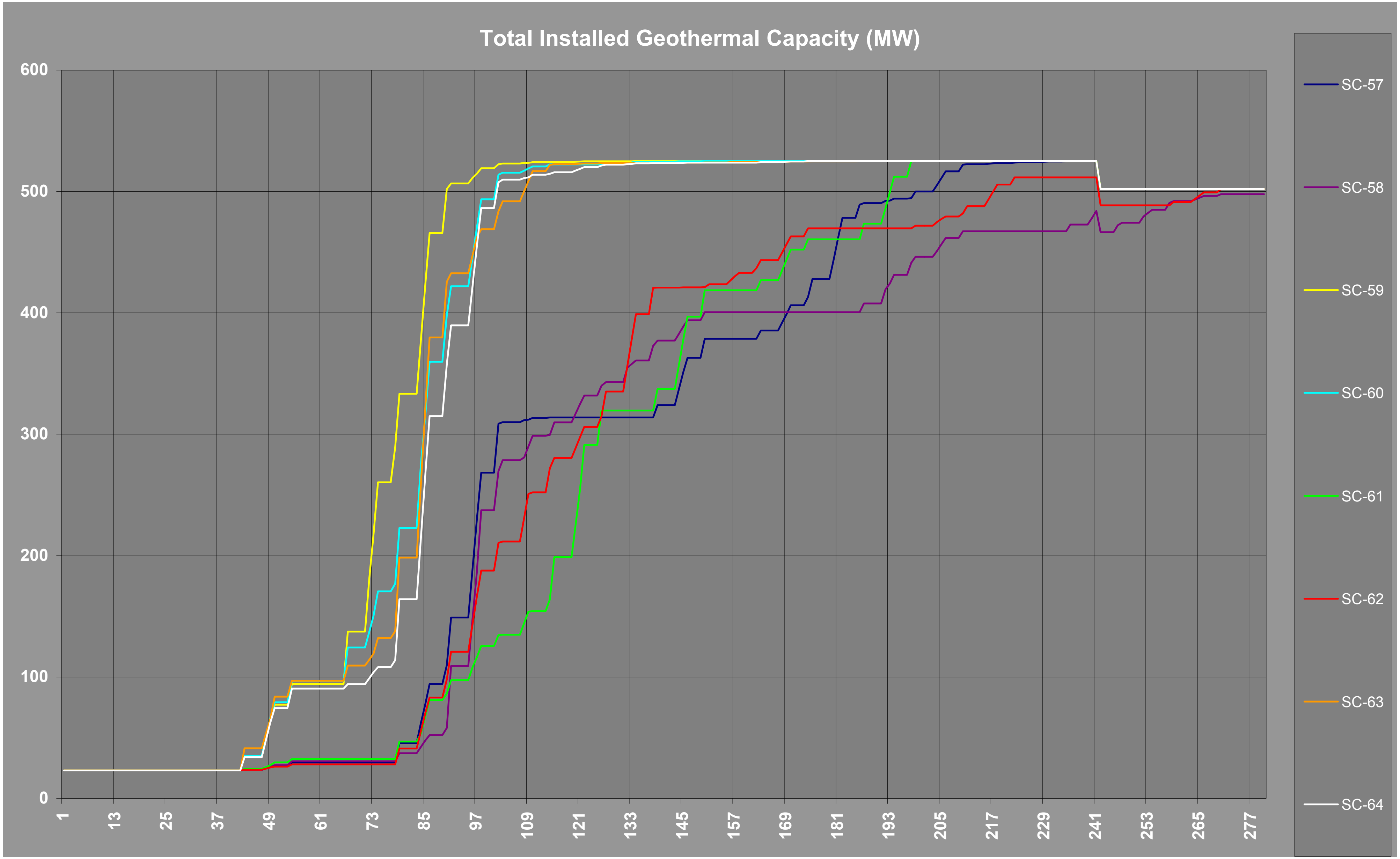

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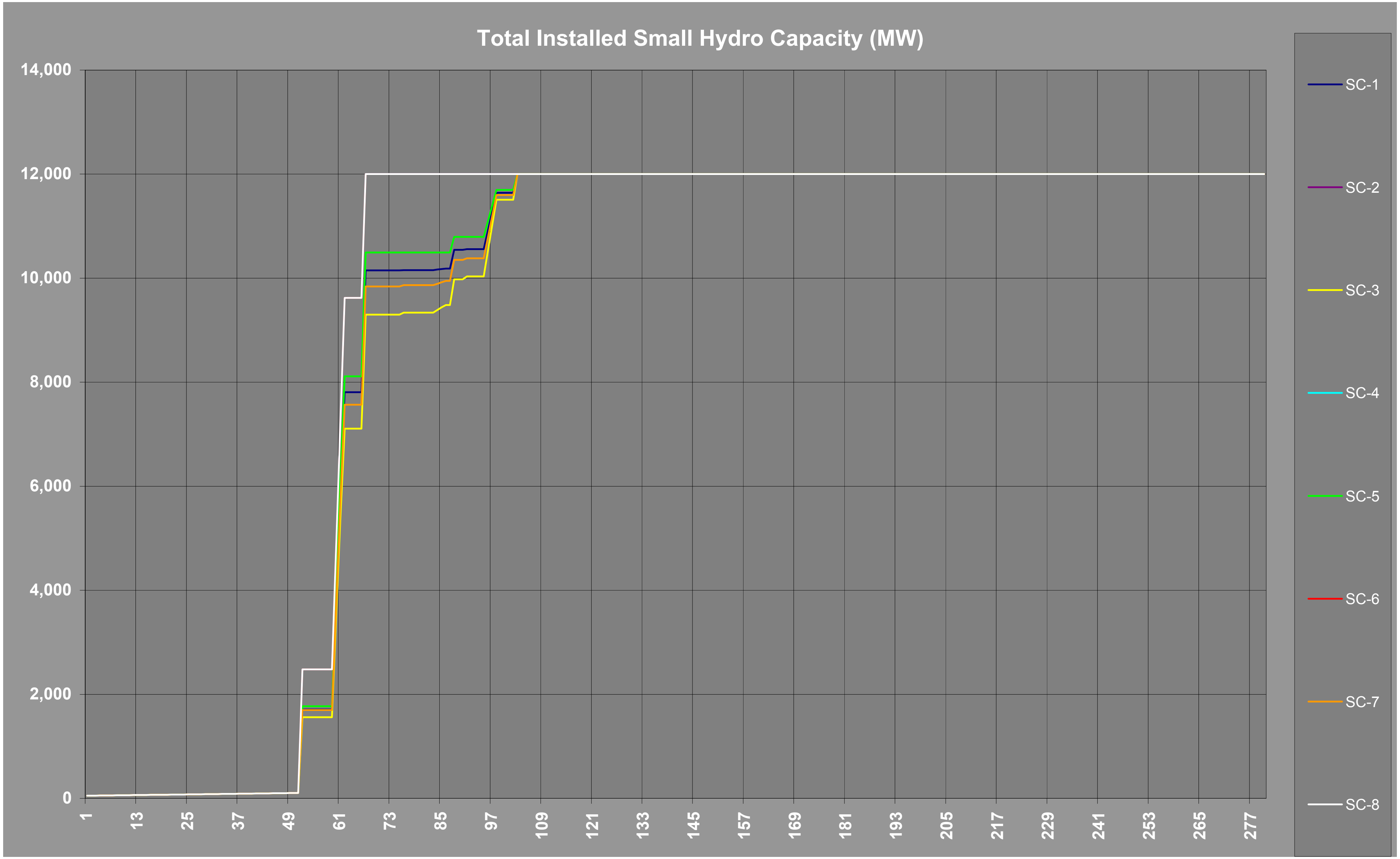

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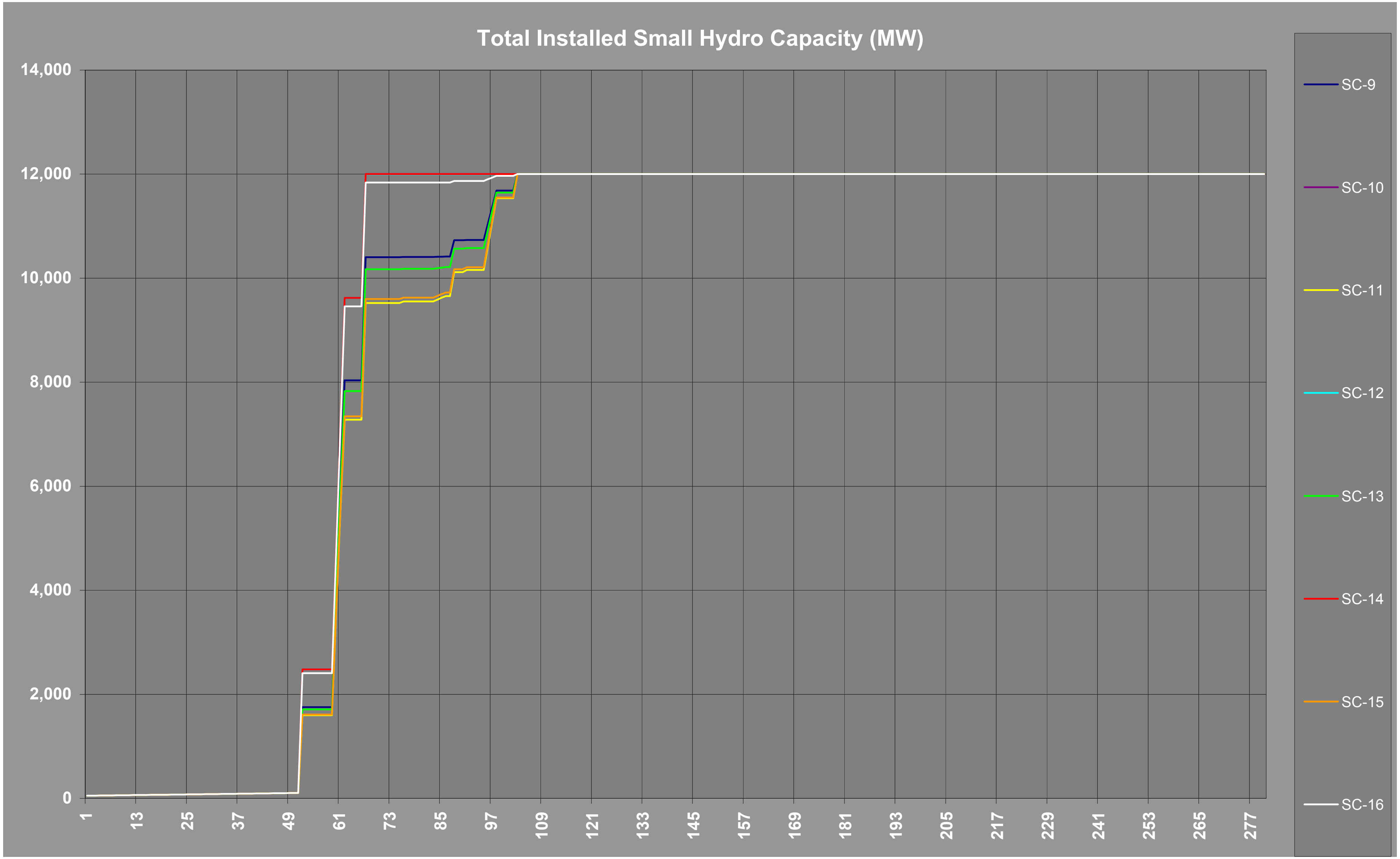
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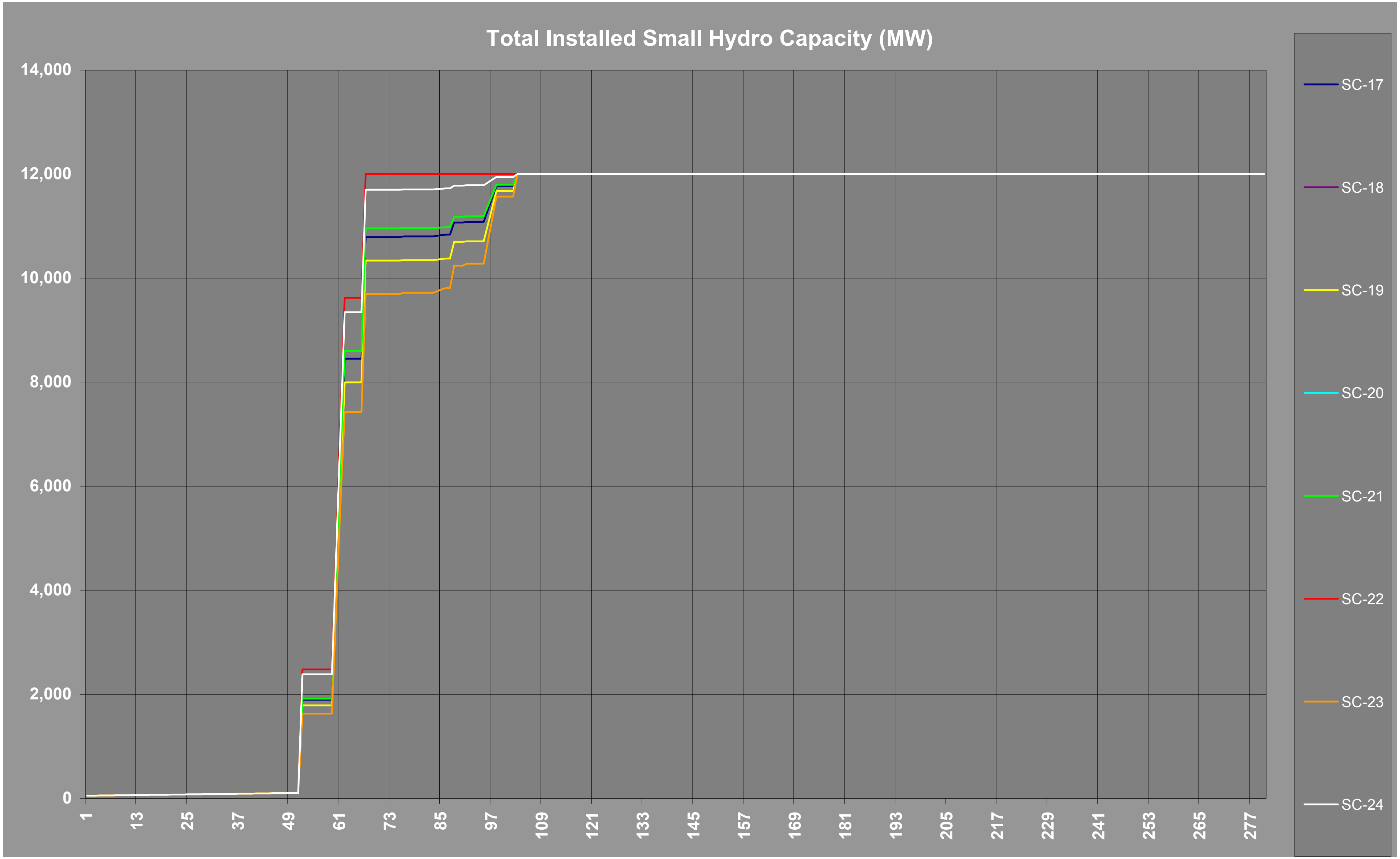

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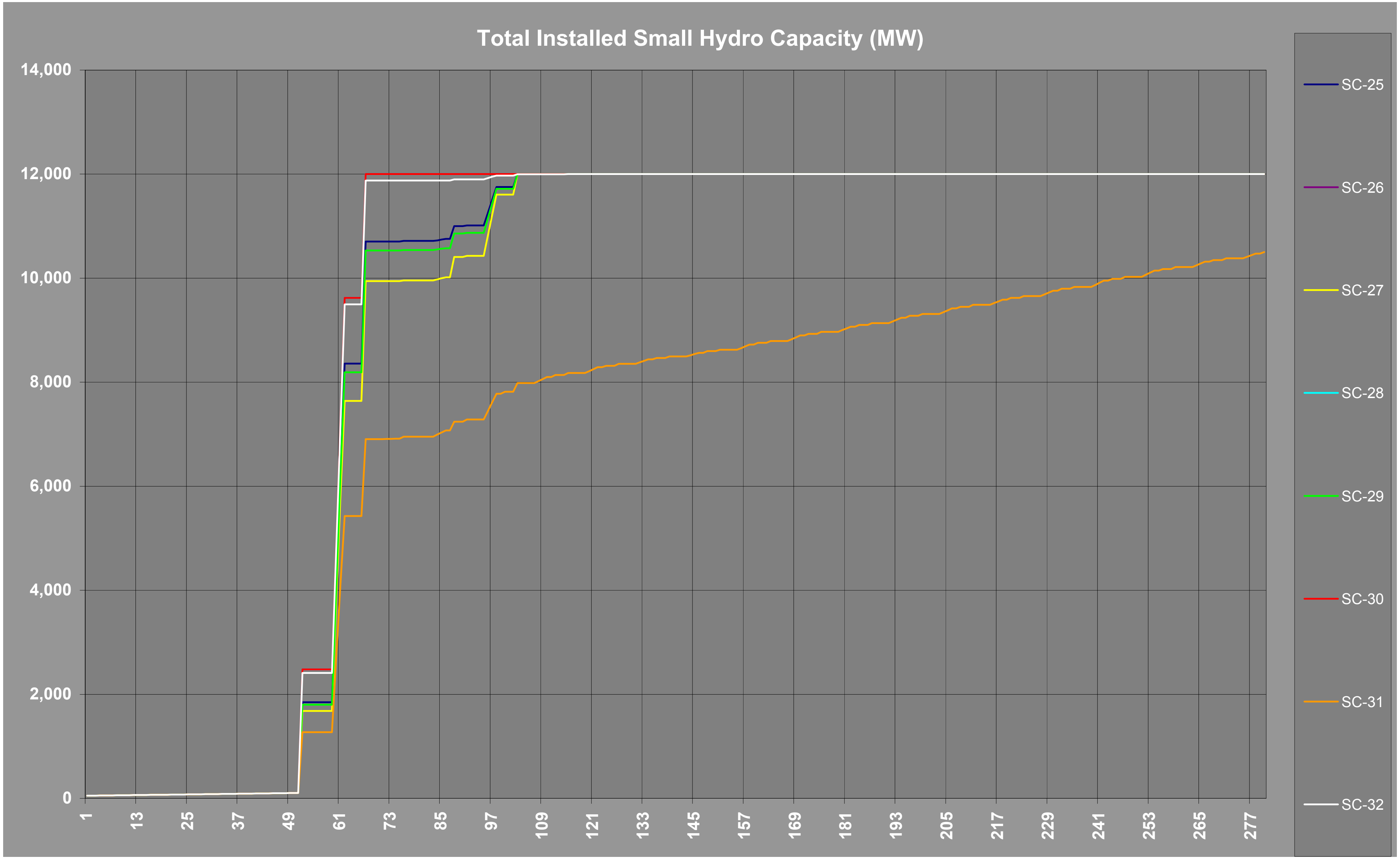

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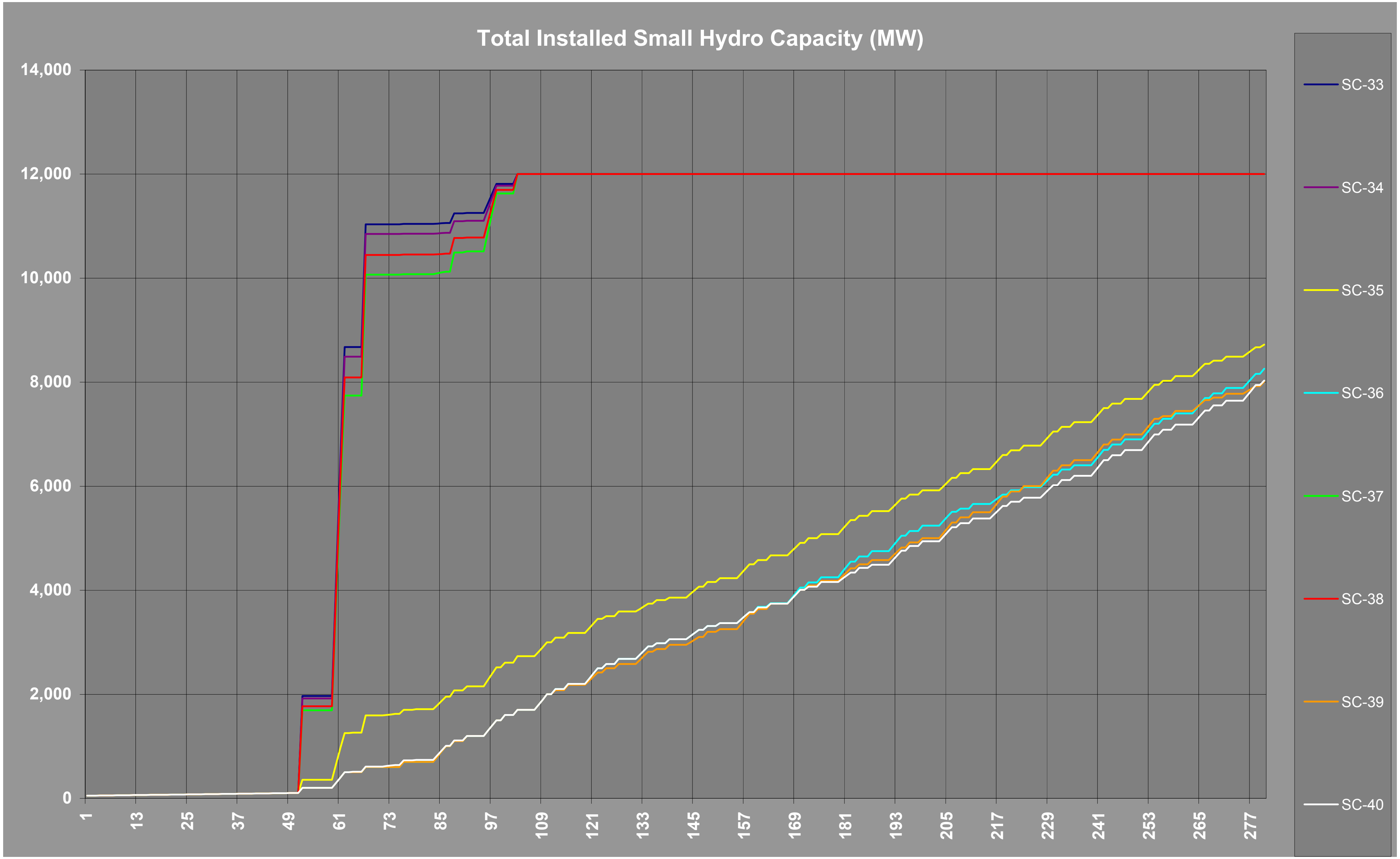

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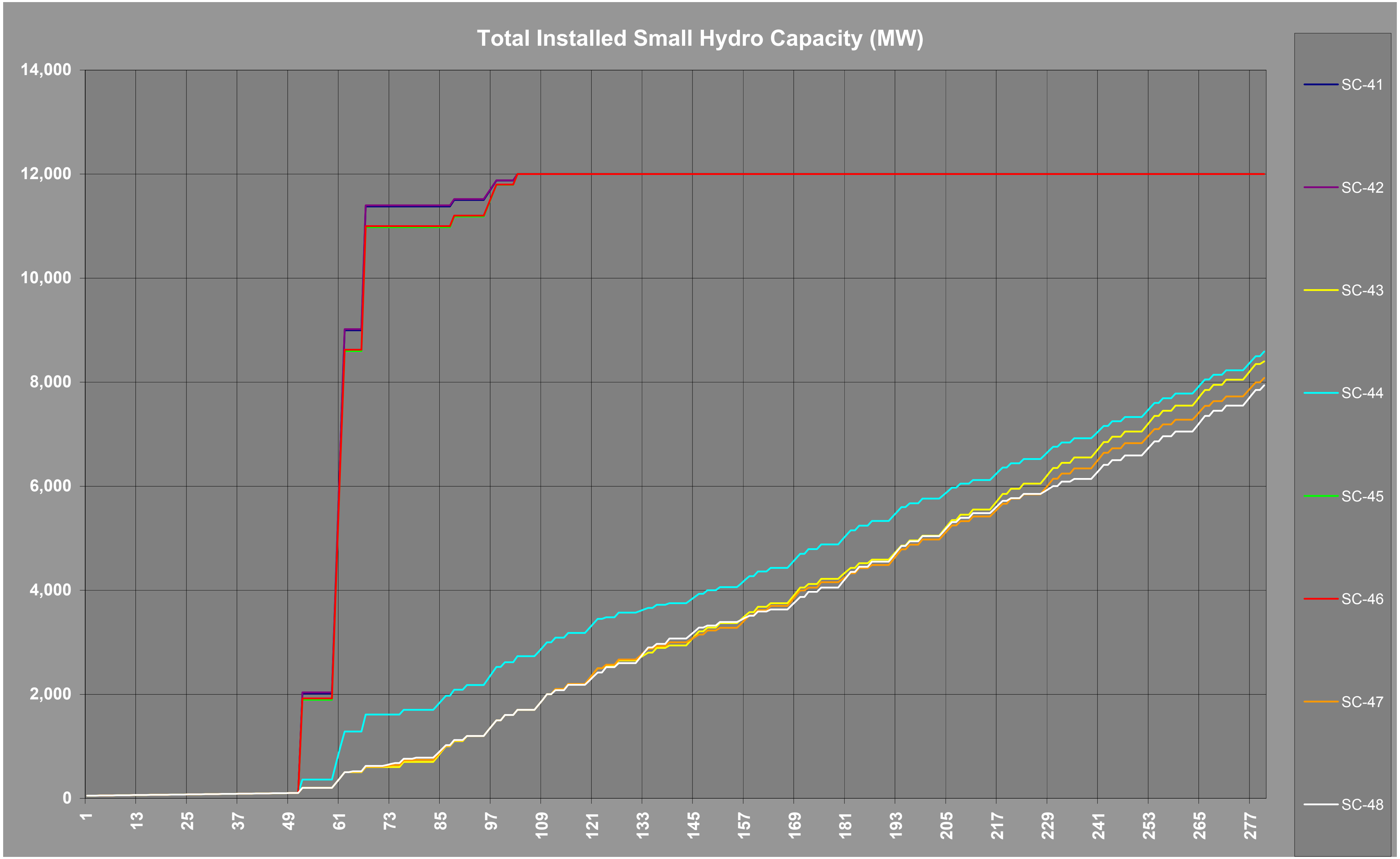
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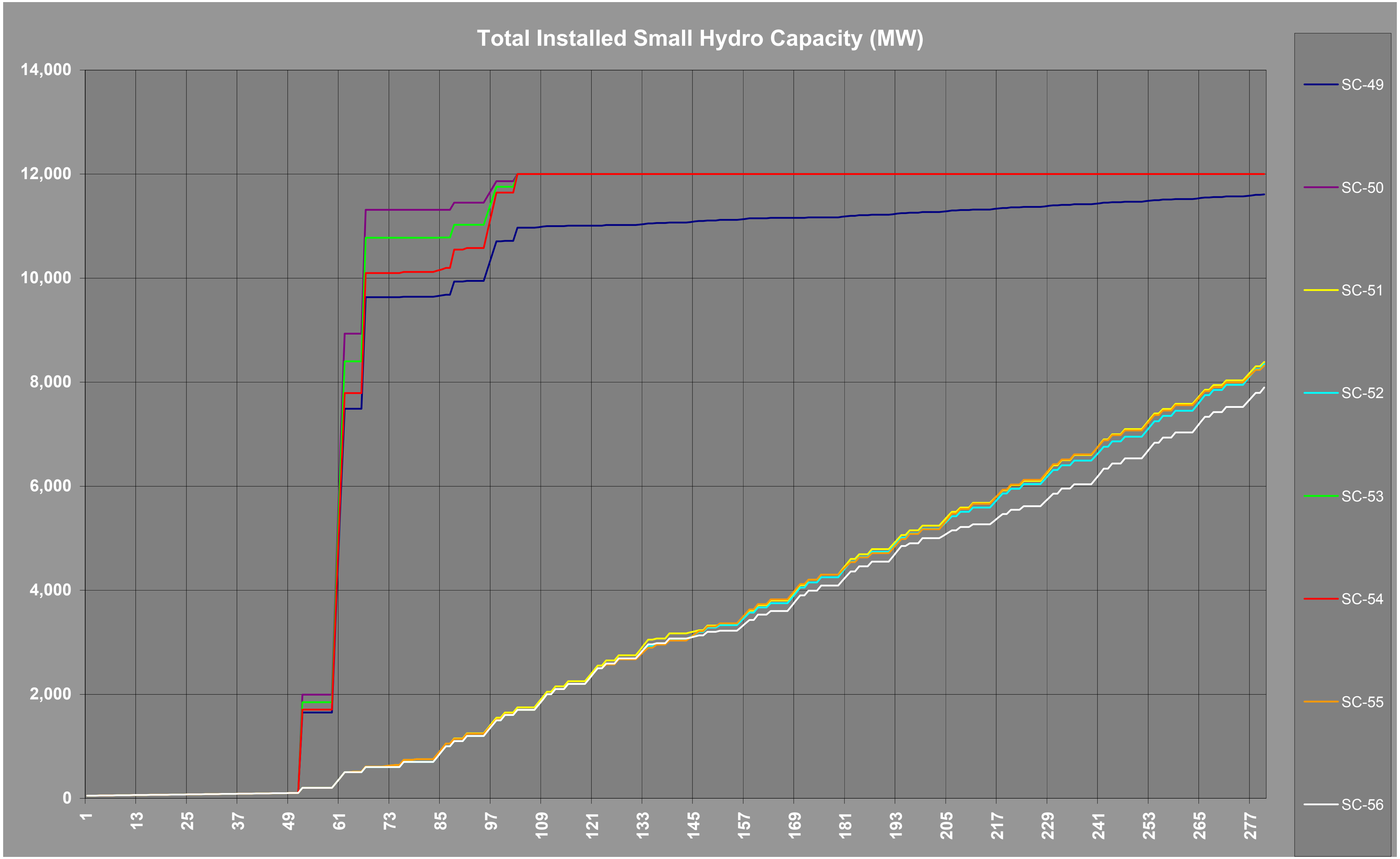
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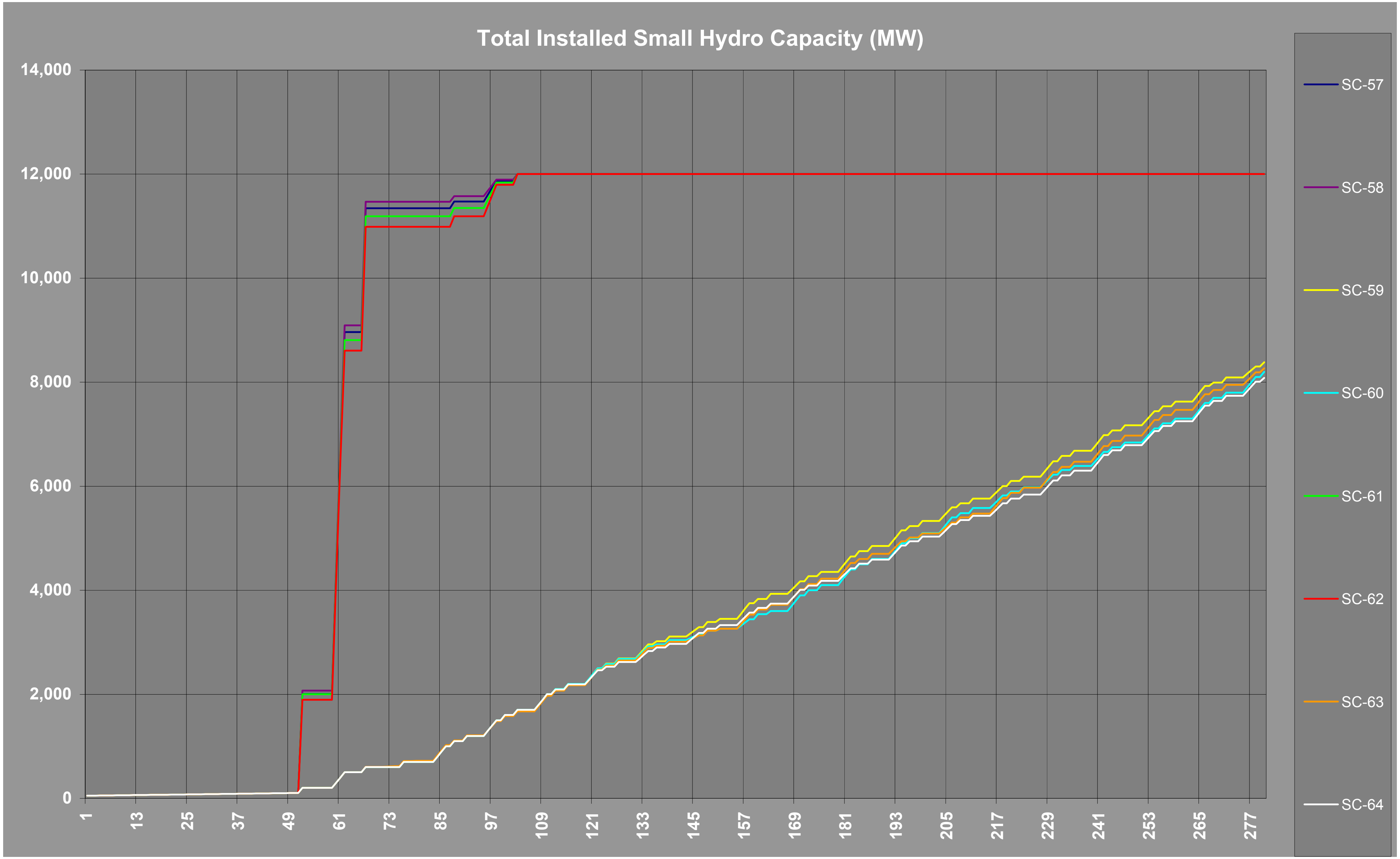
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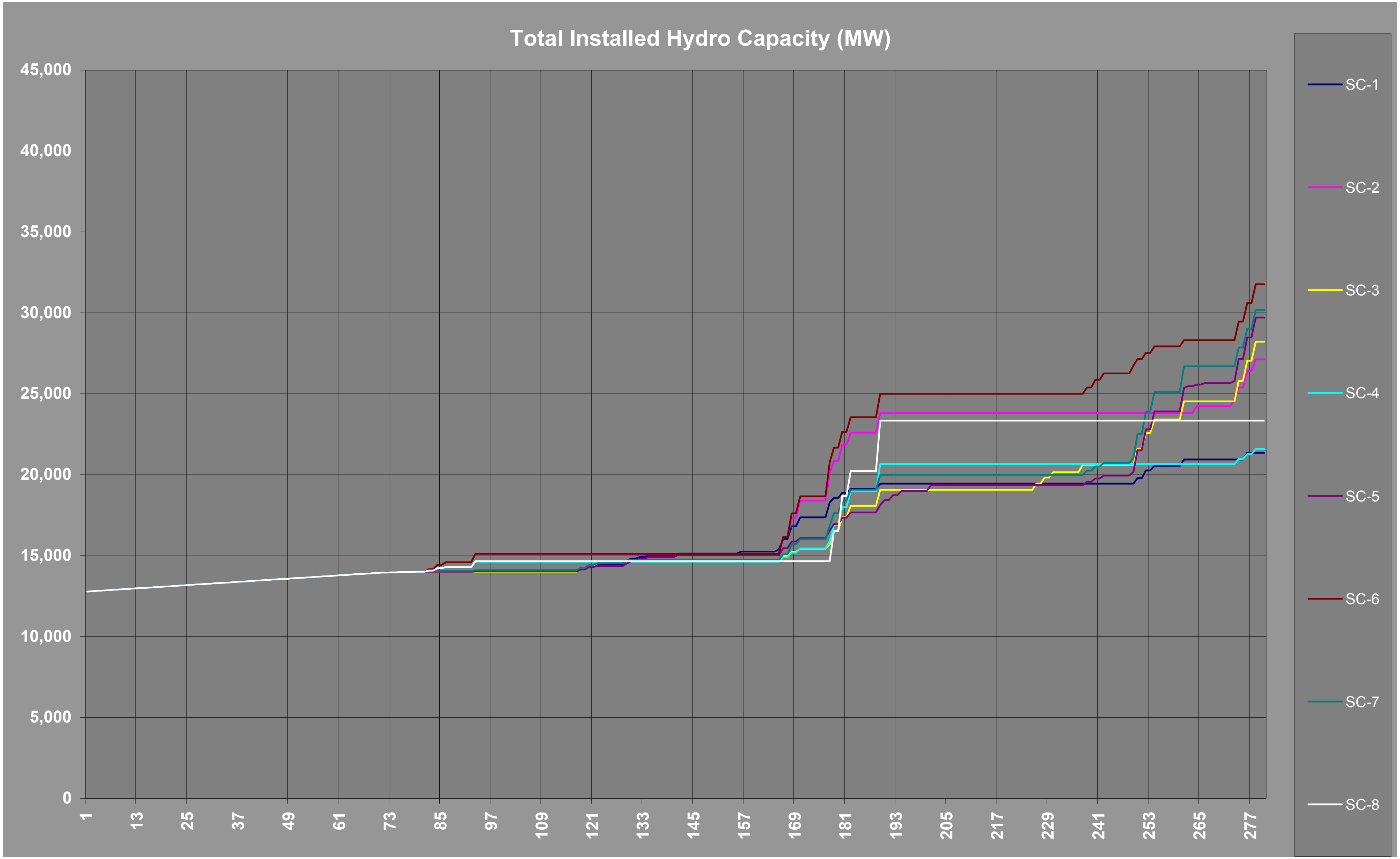

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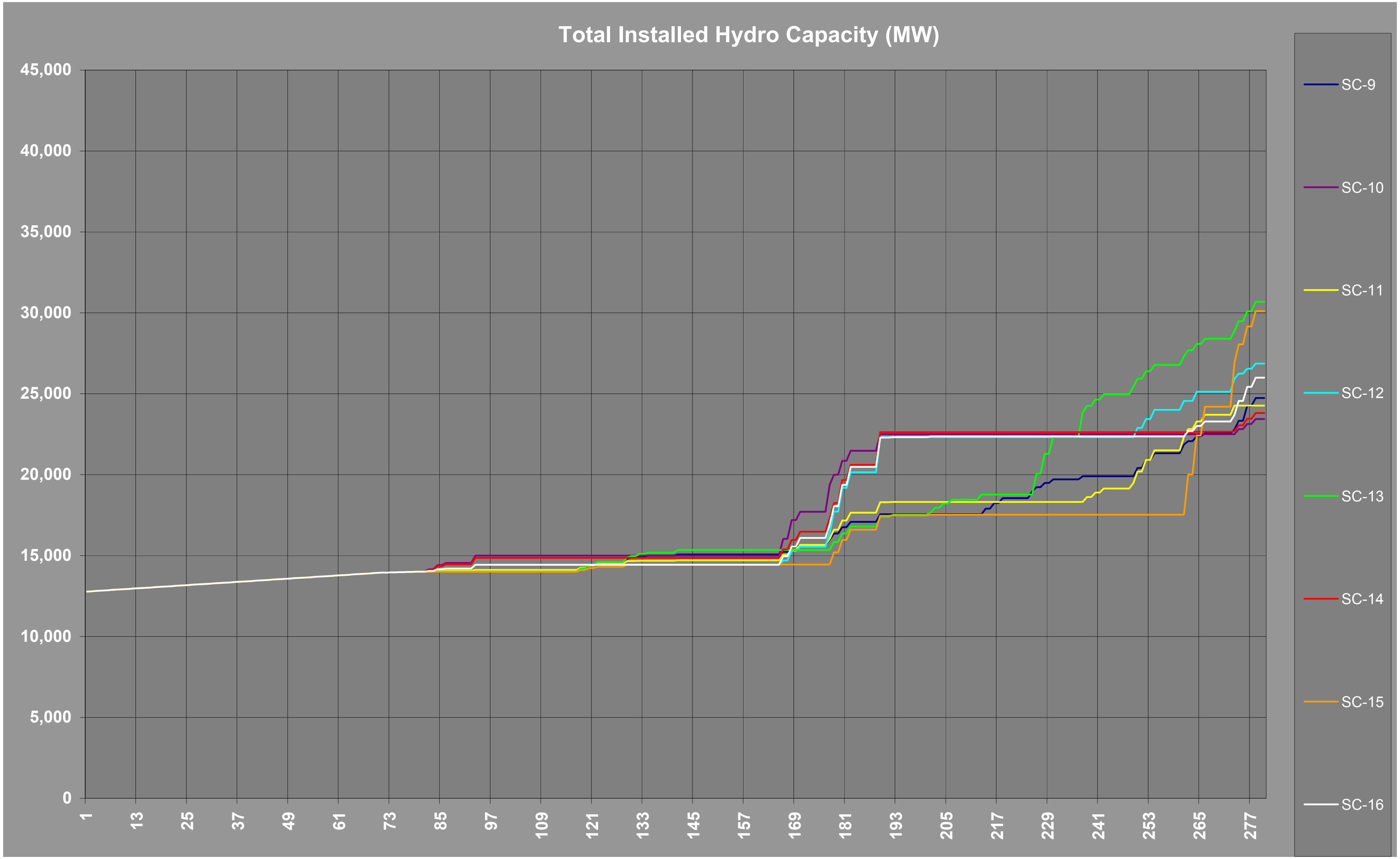
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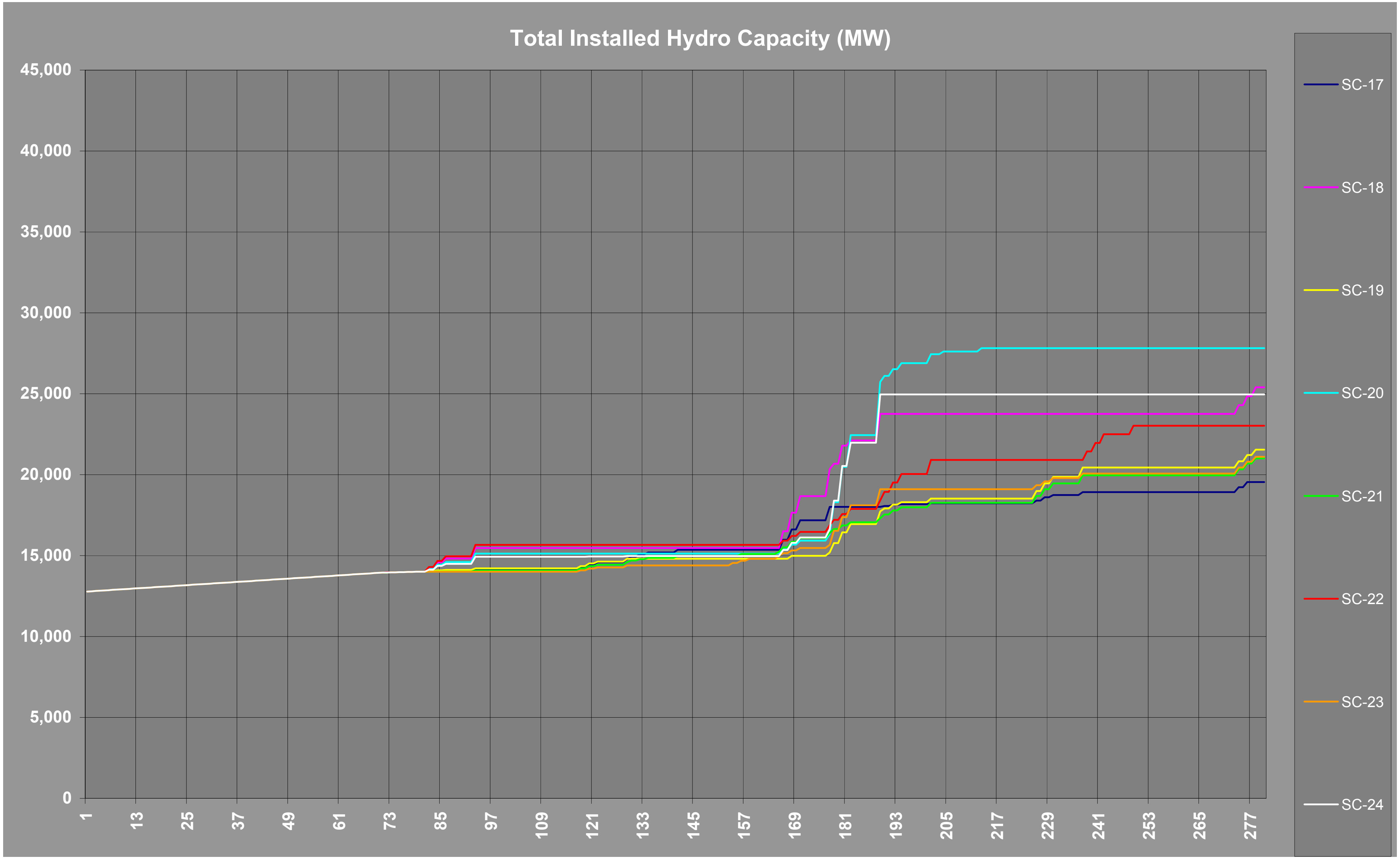
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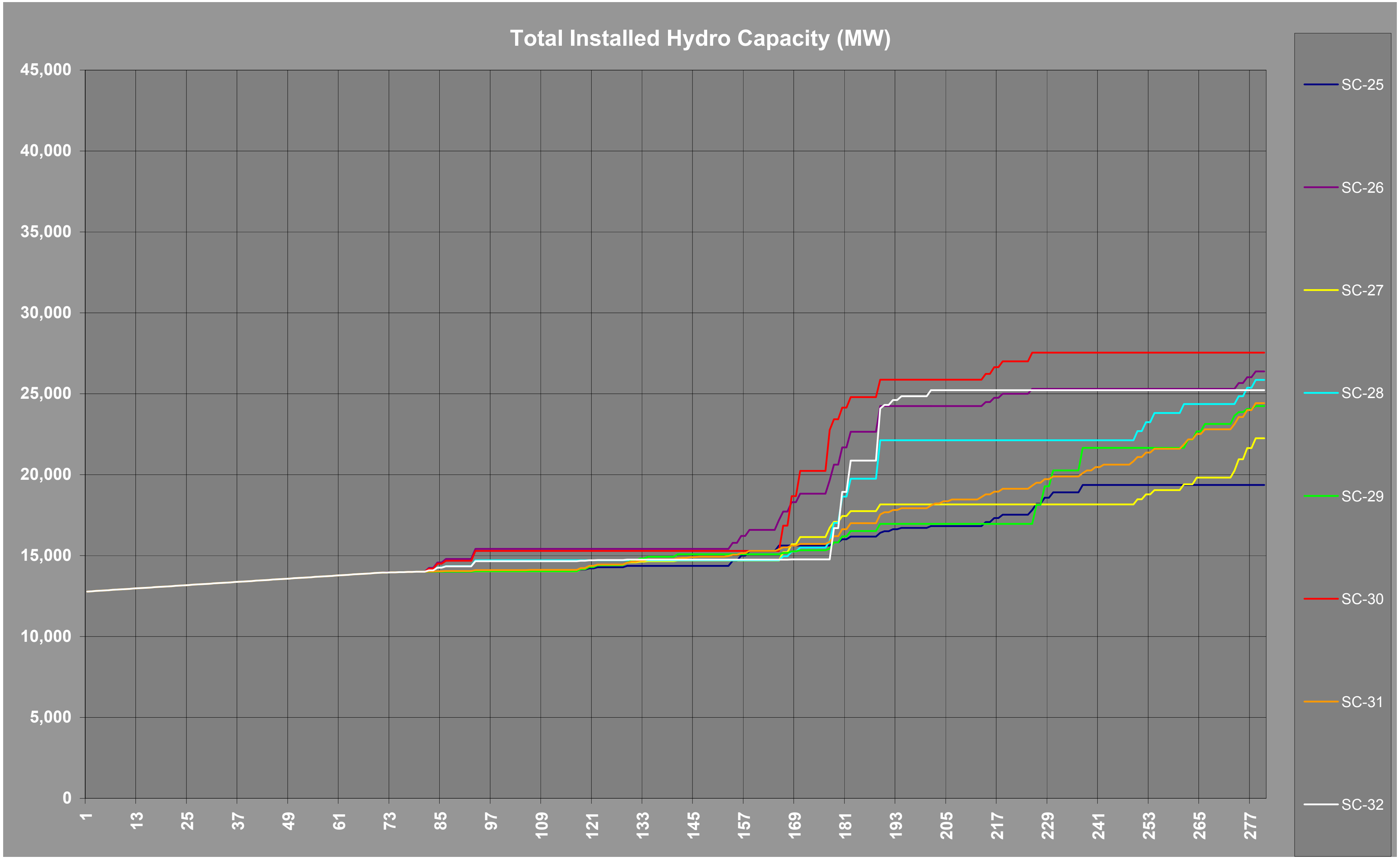
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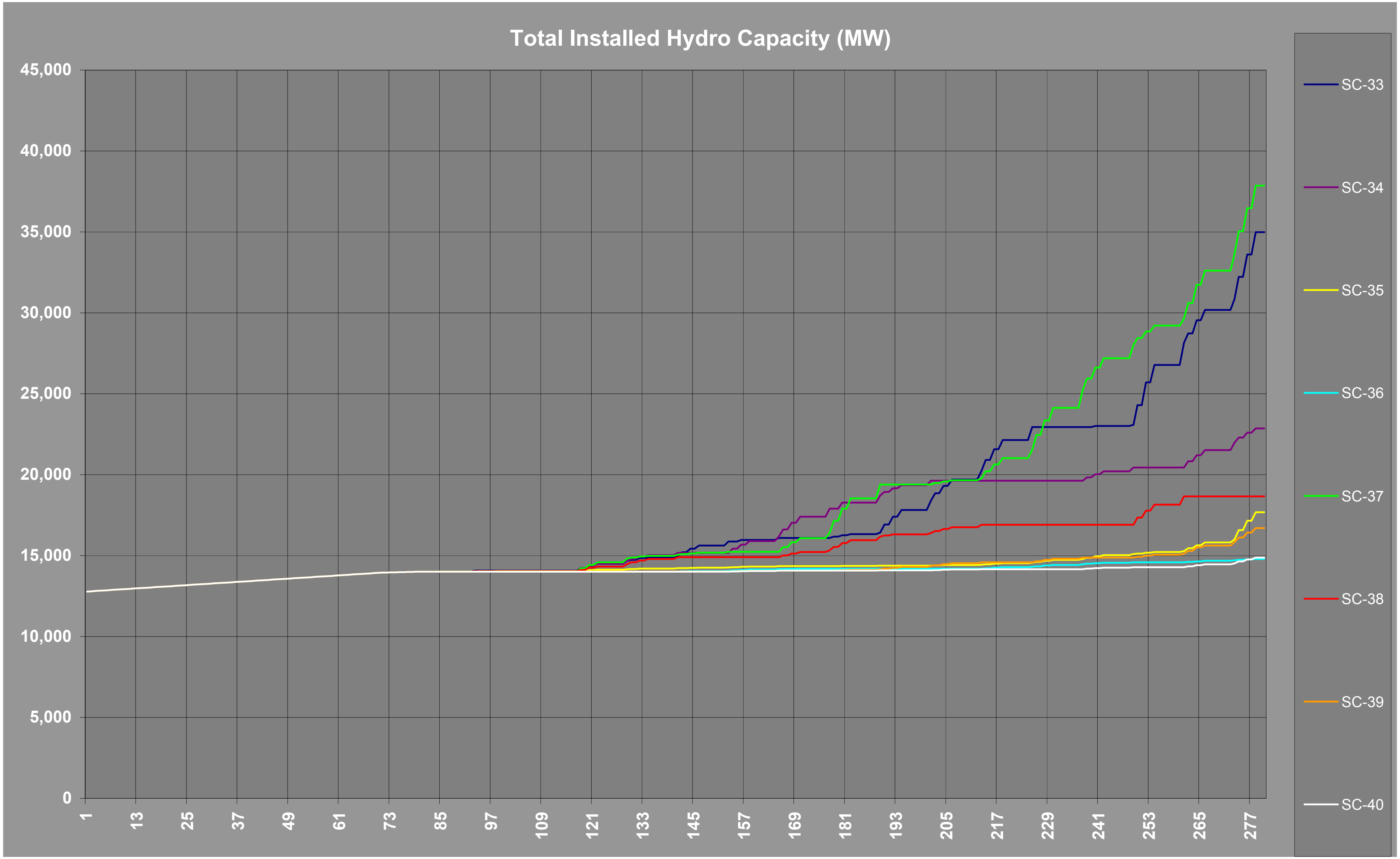
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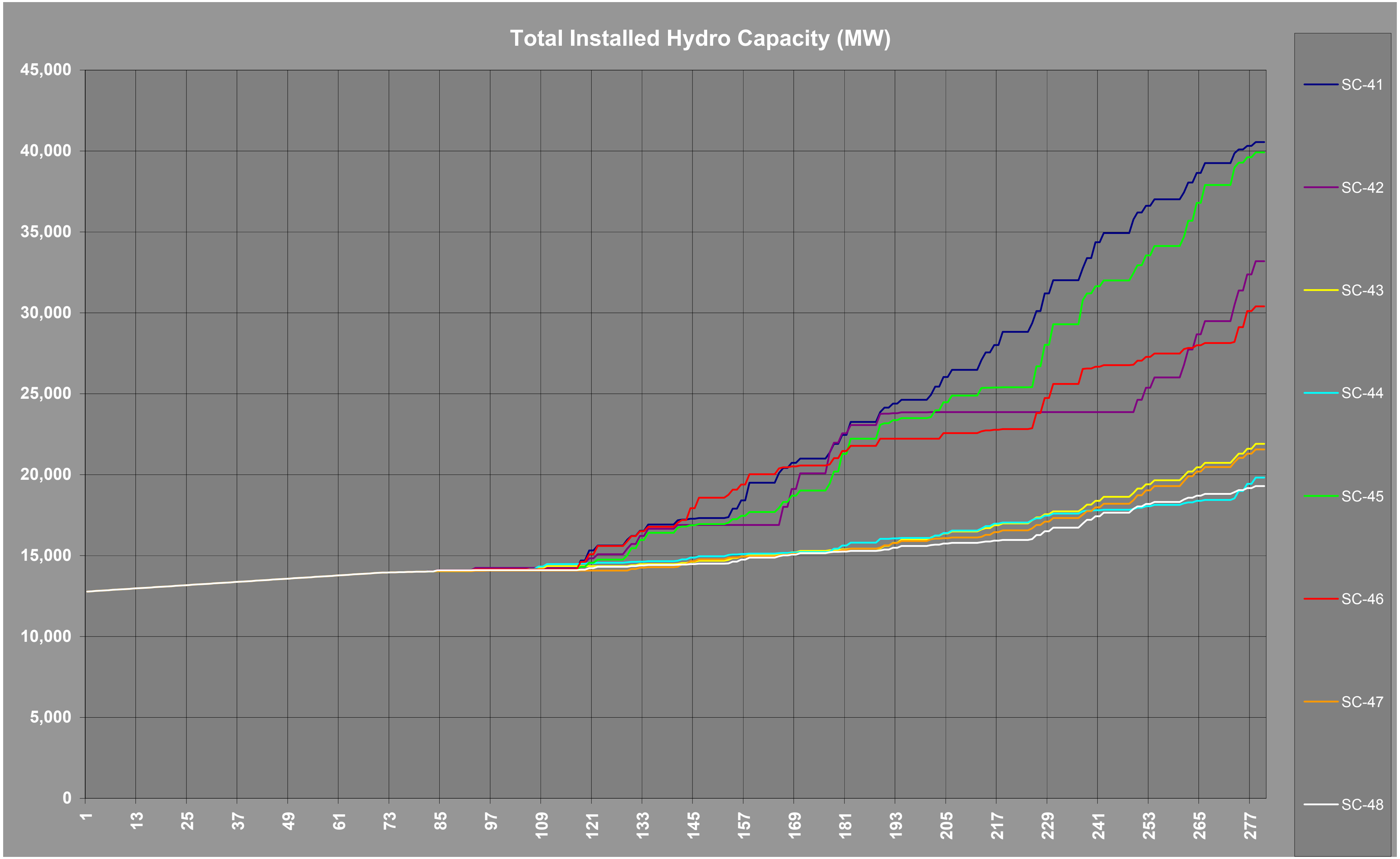

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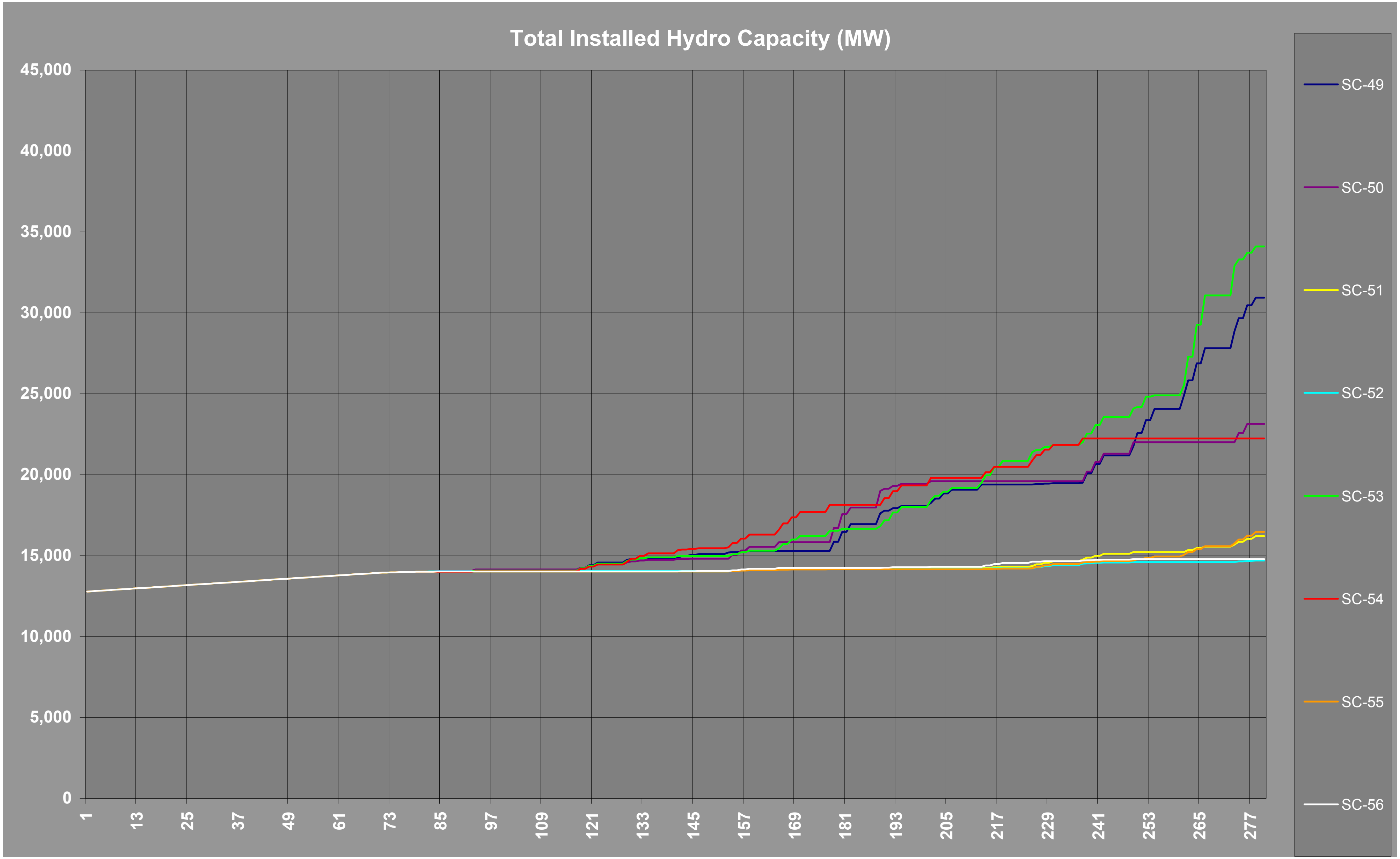

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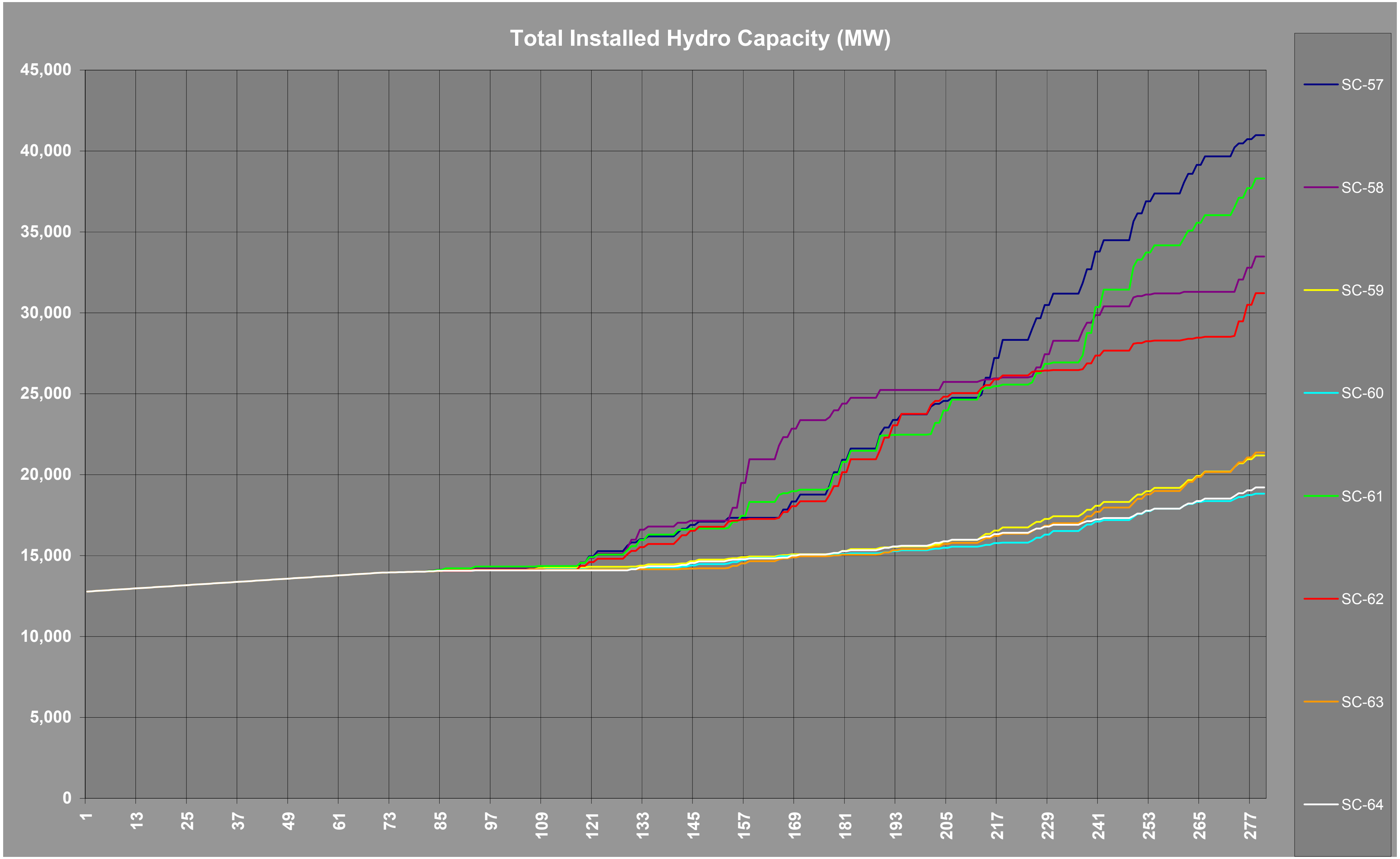

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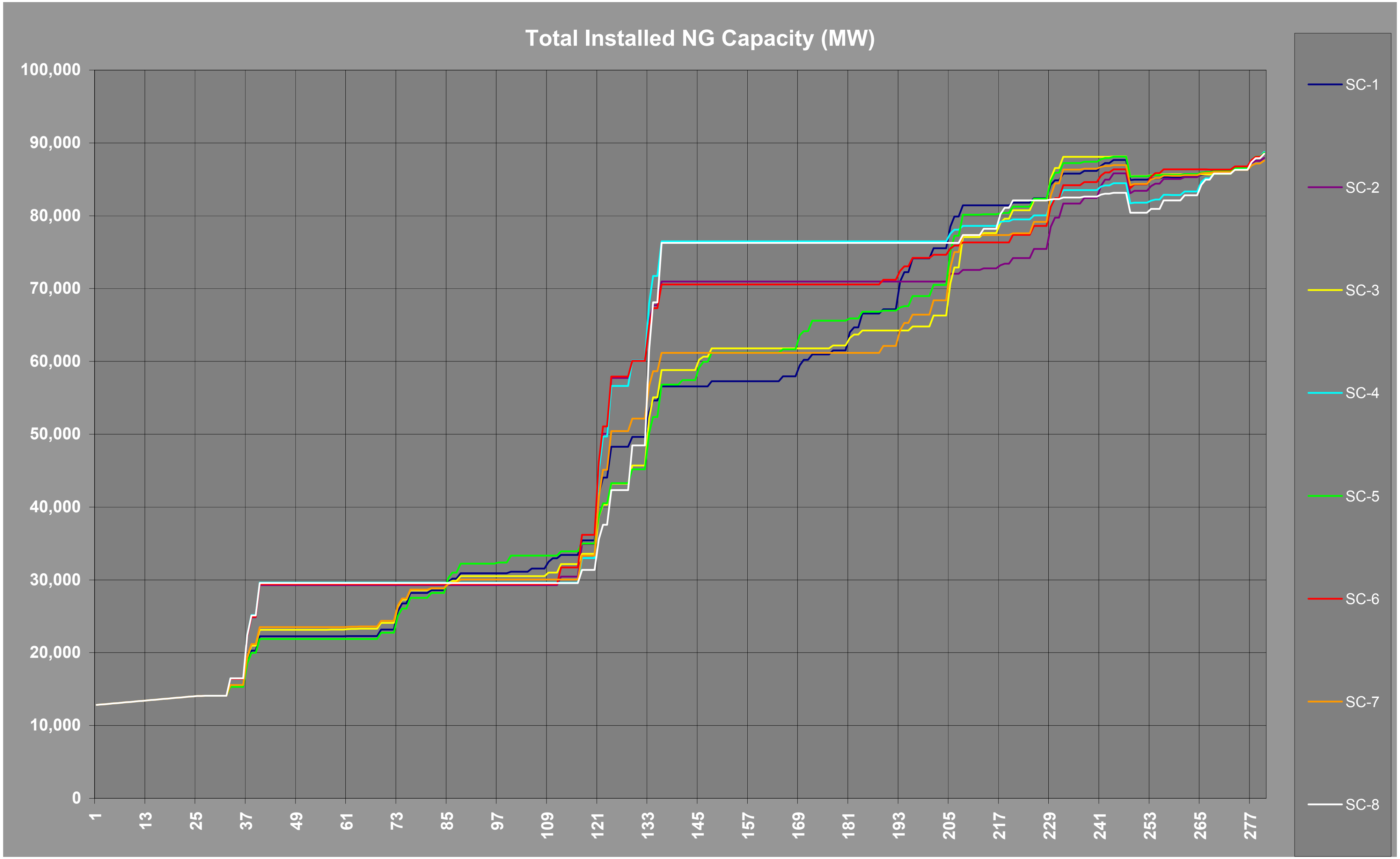

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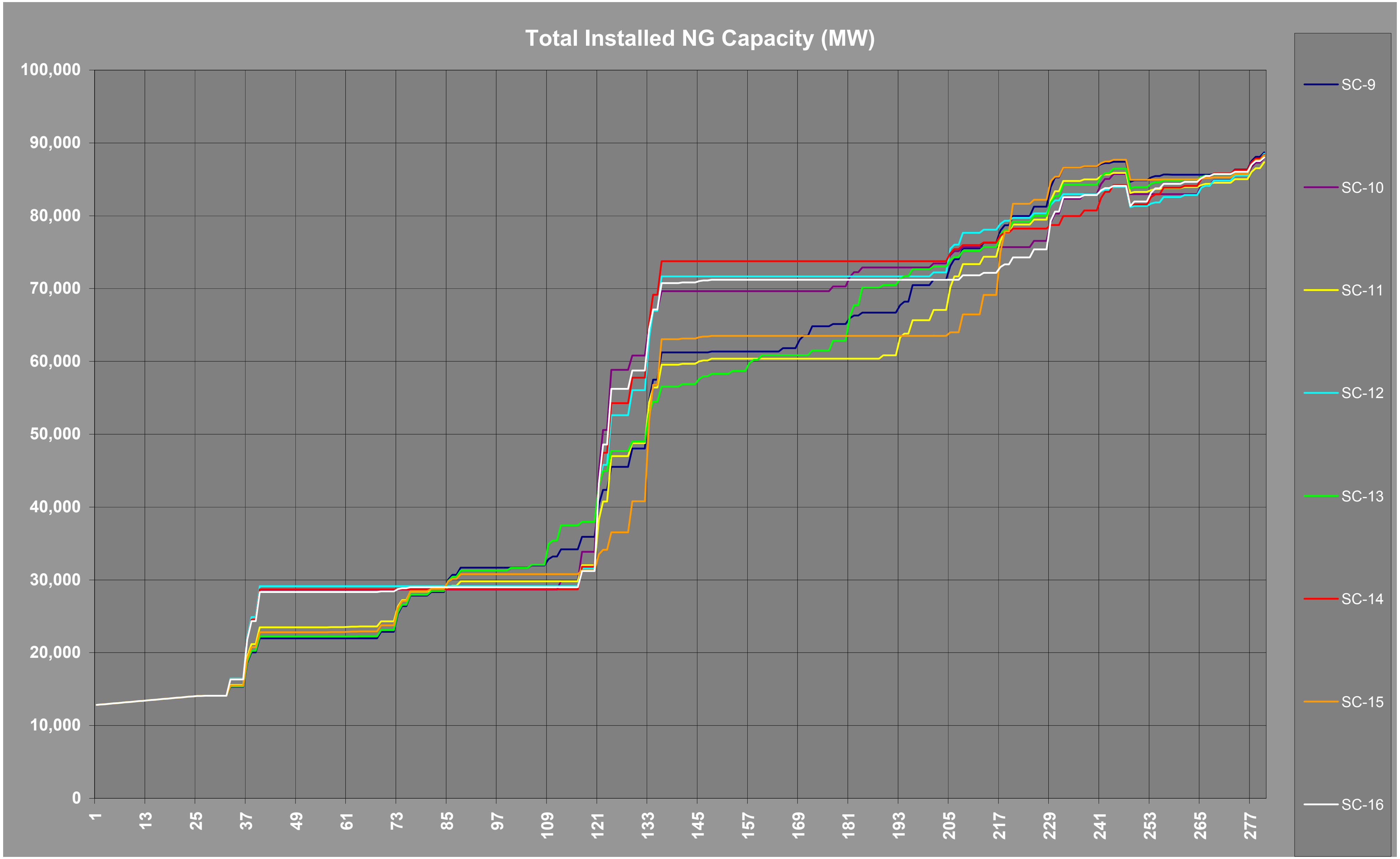

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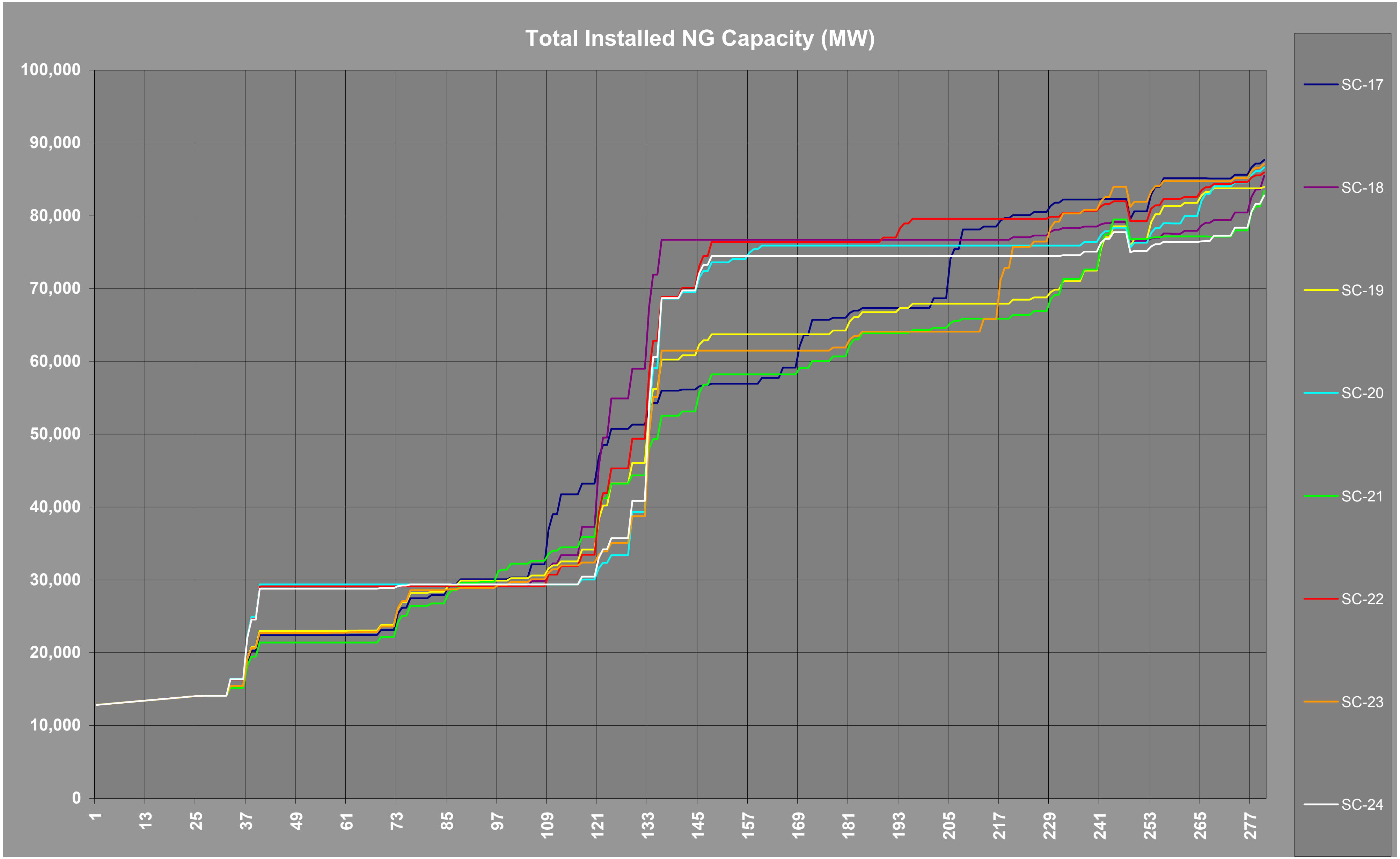

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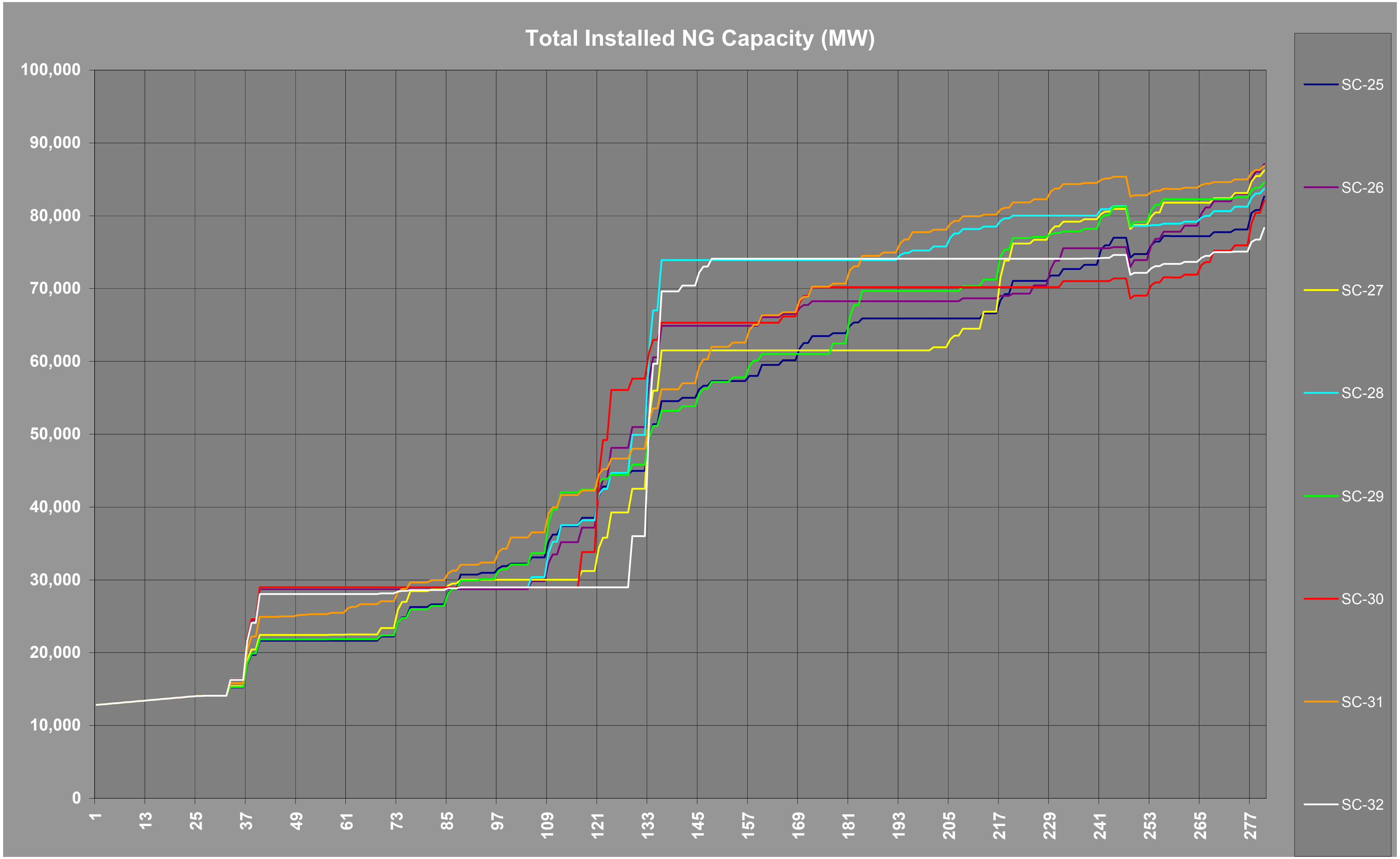

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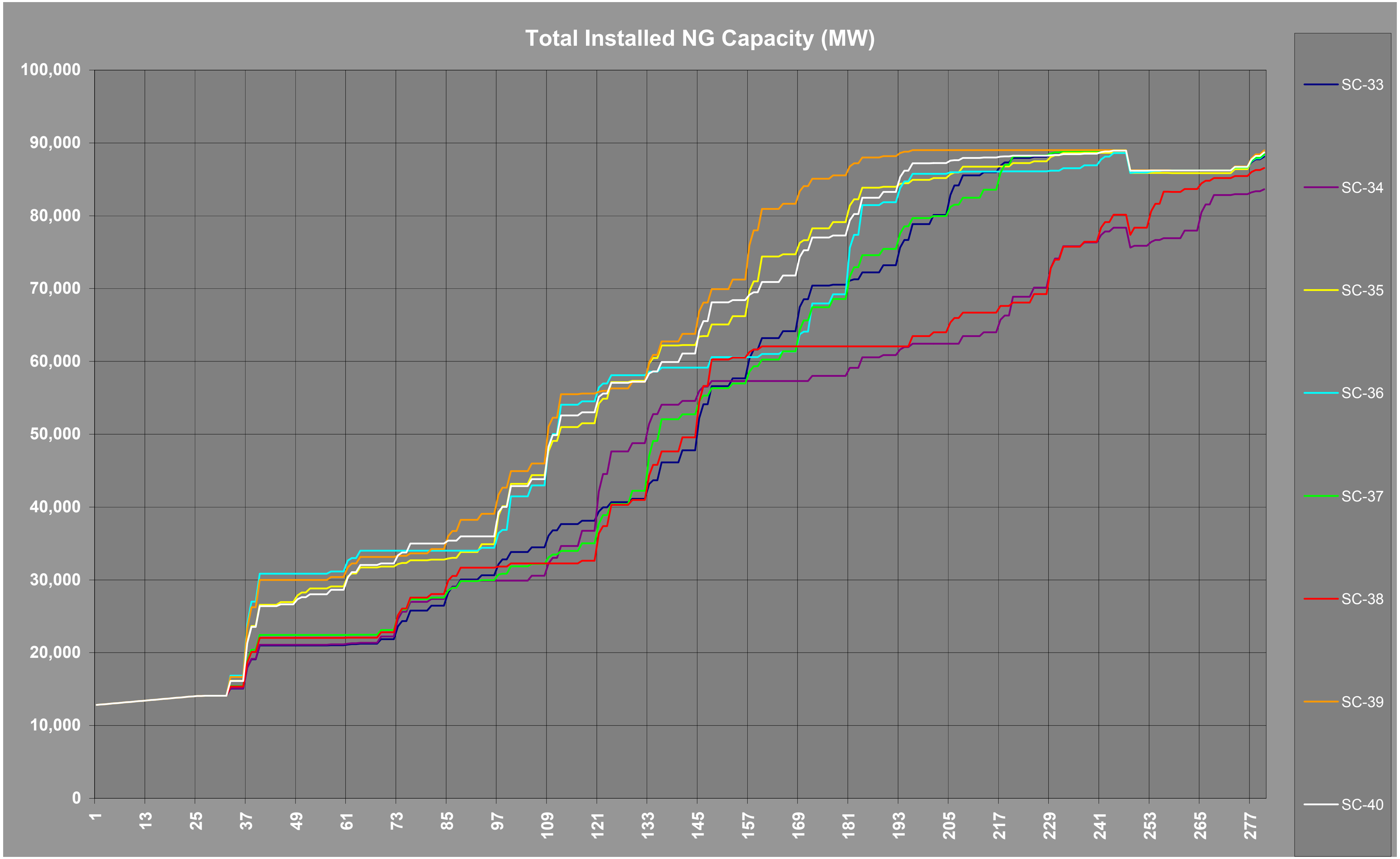
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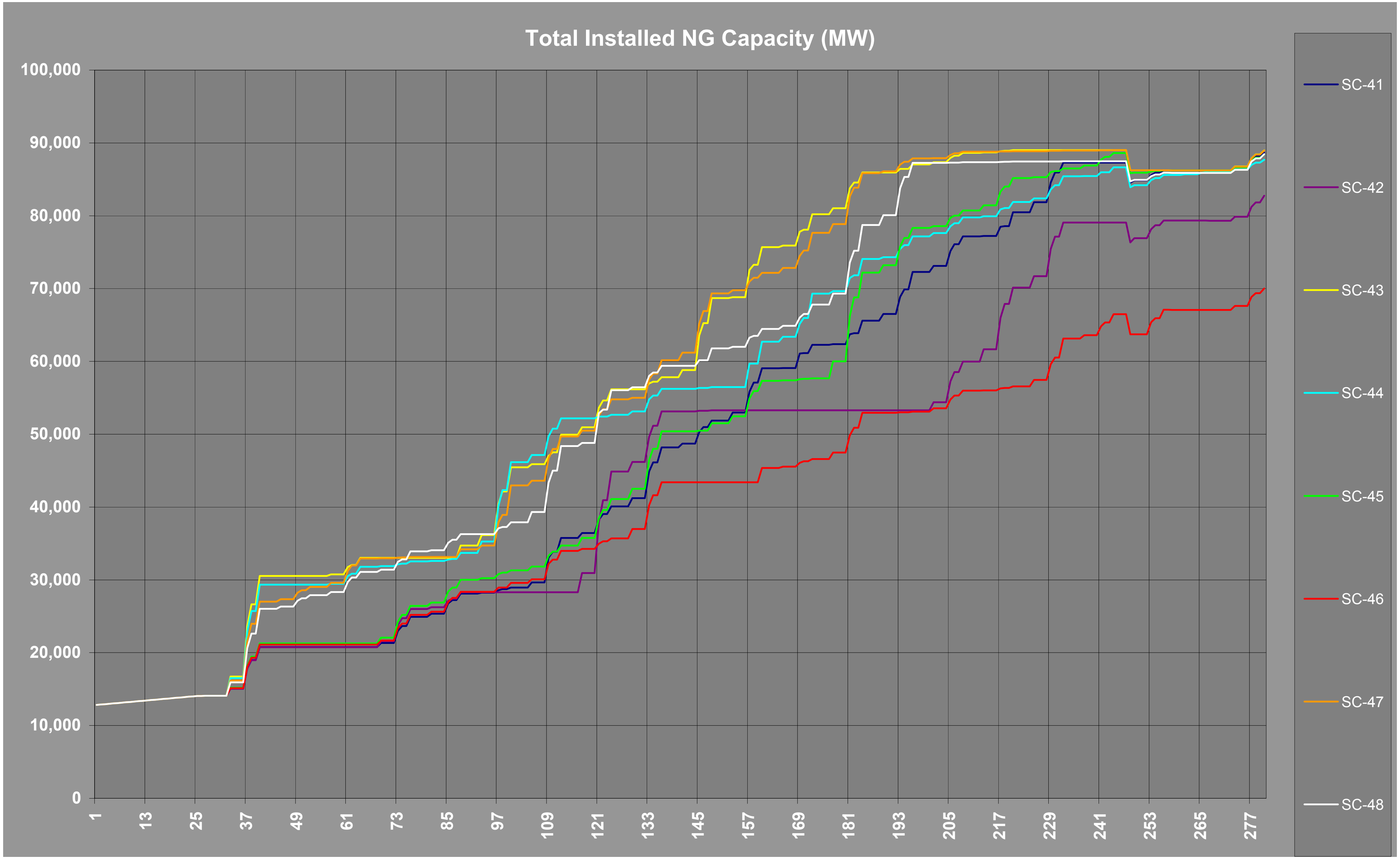
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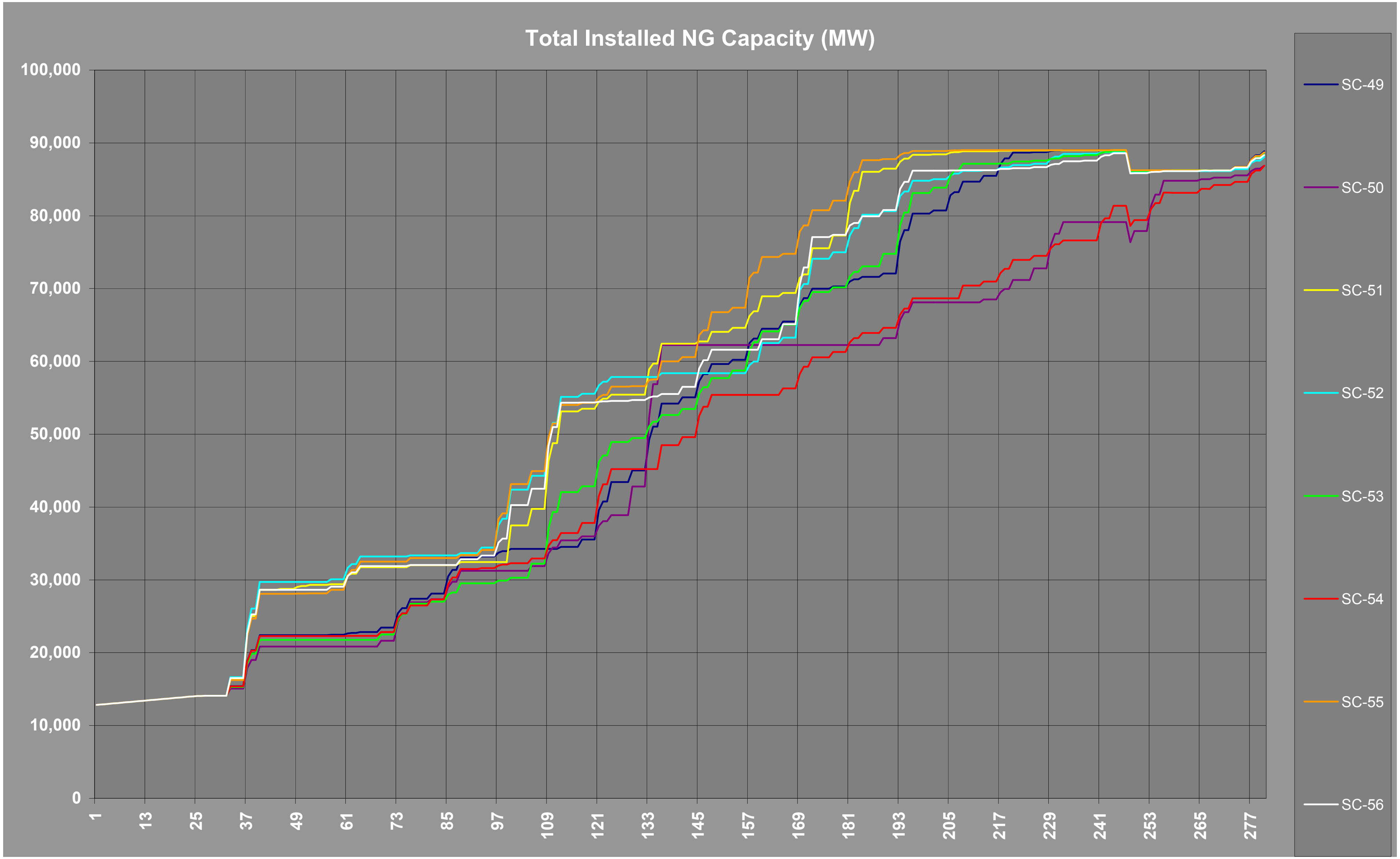
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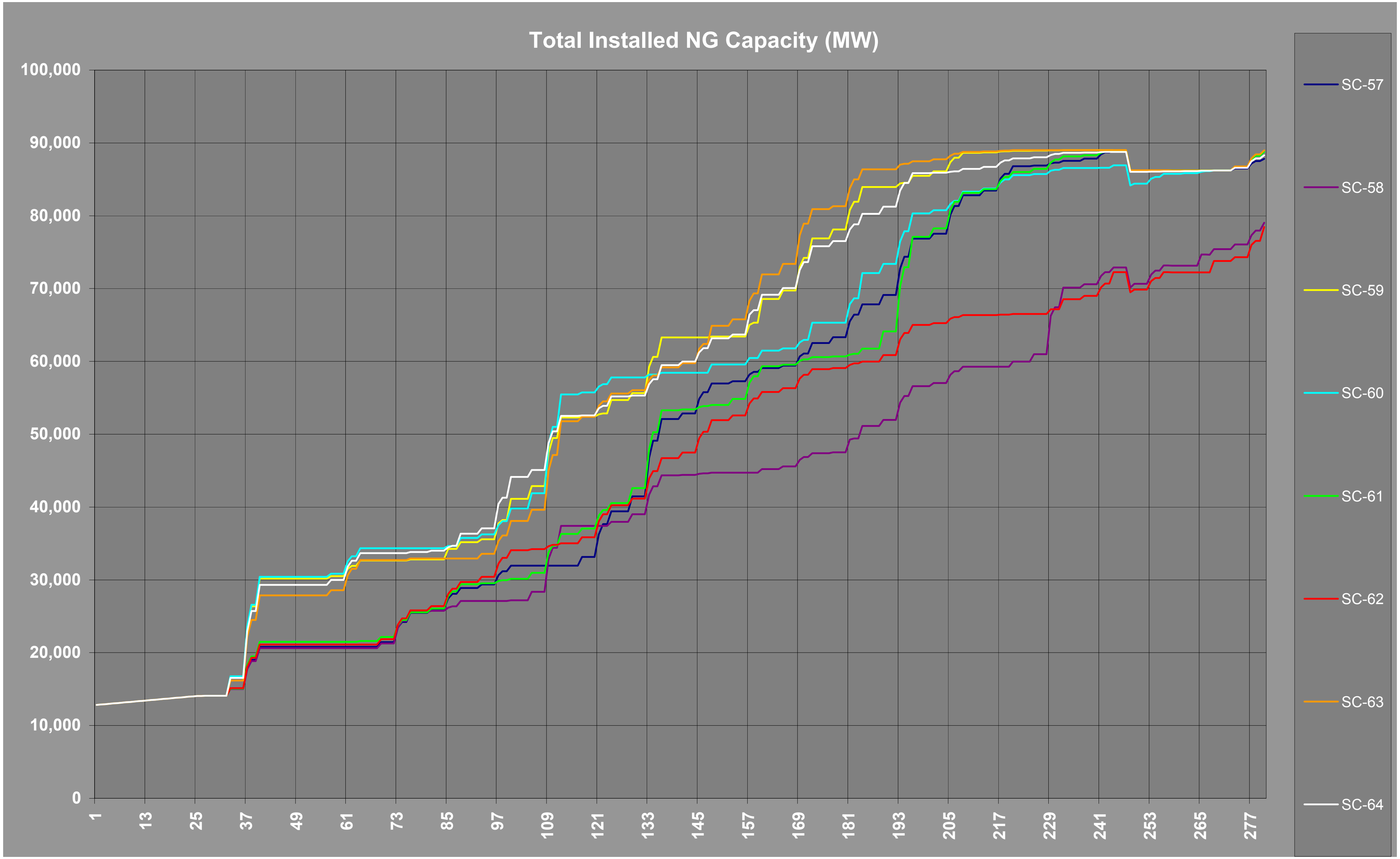
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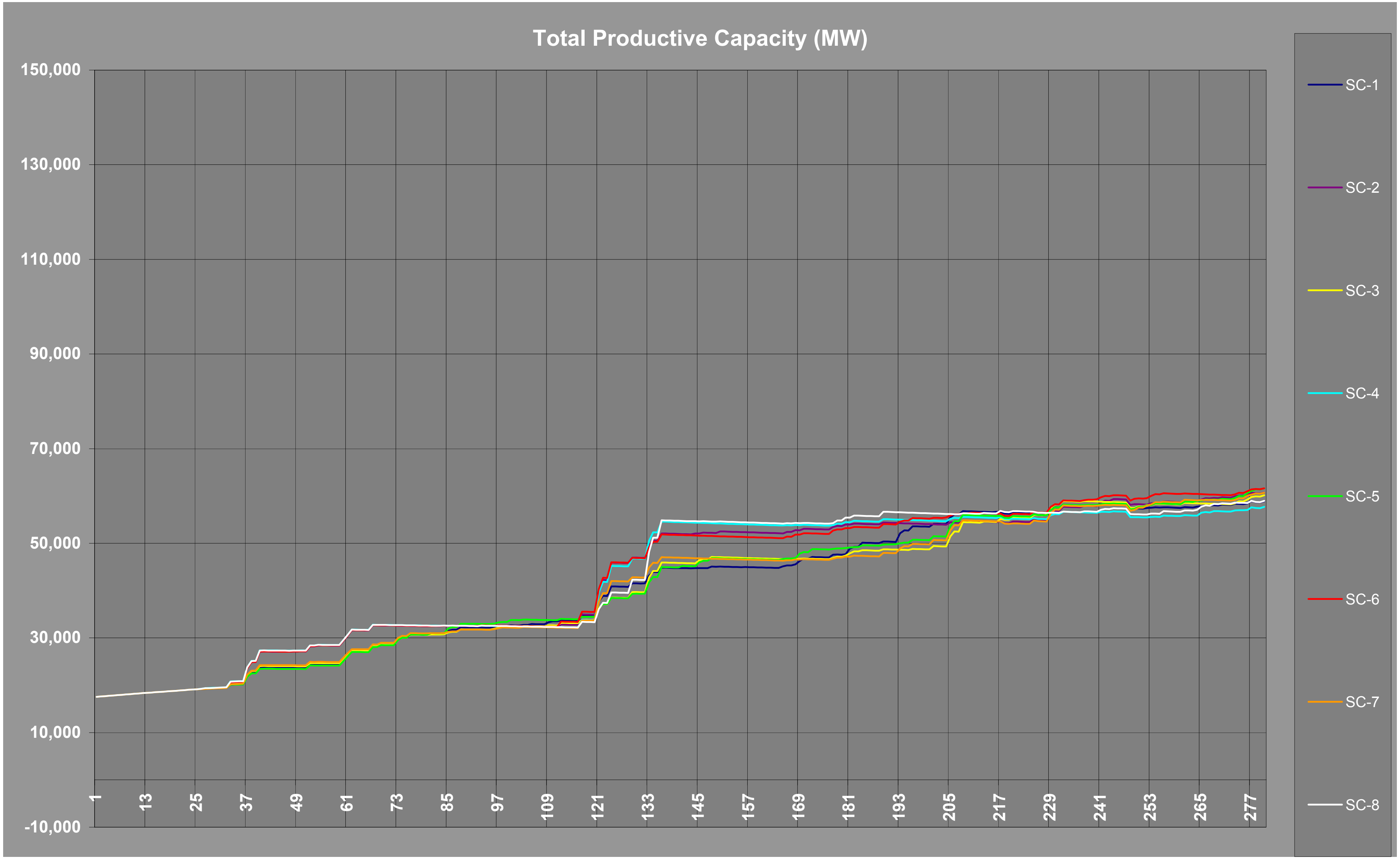

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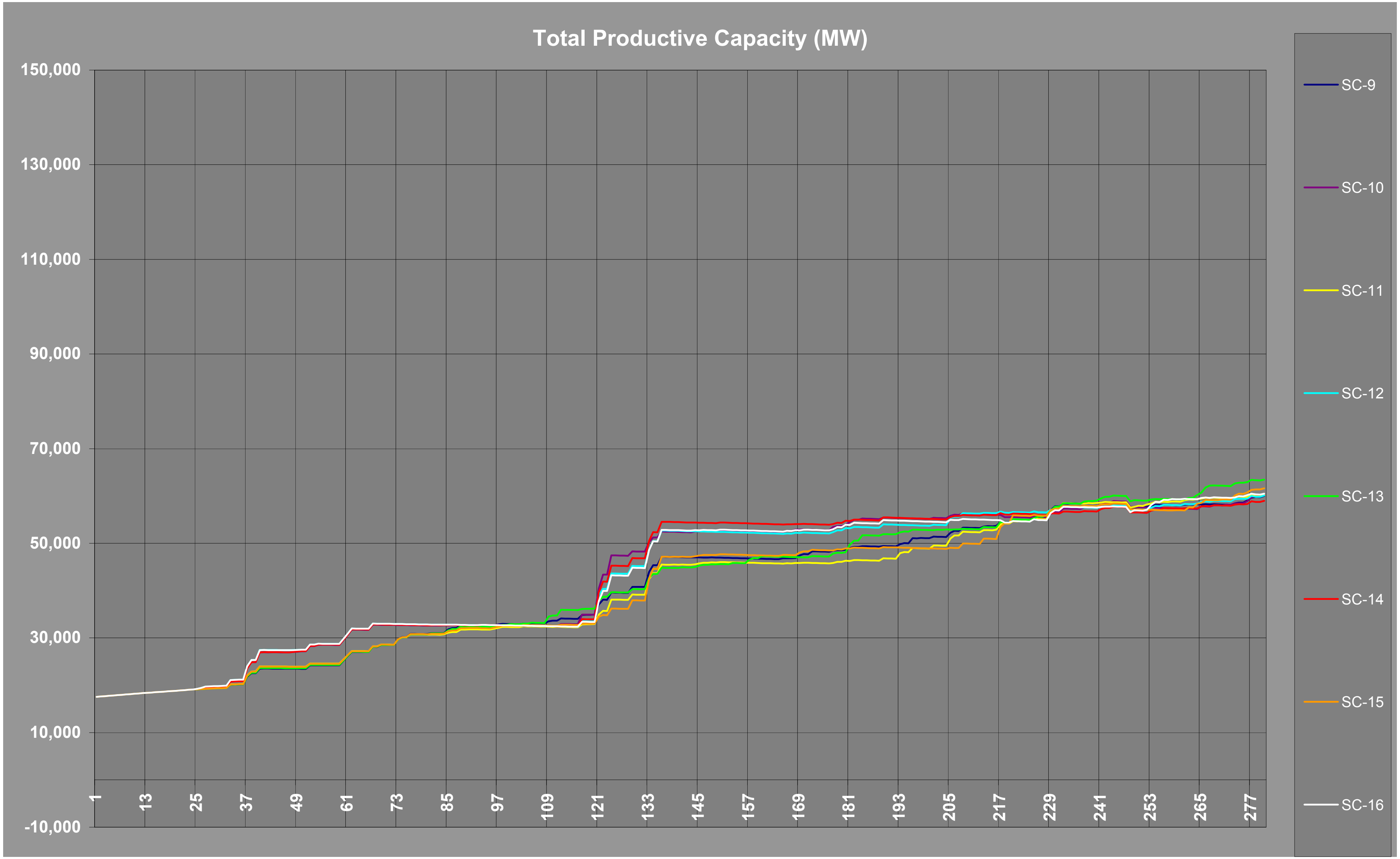

Total Productive Capacity (MW)
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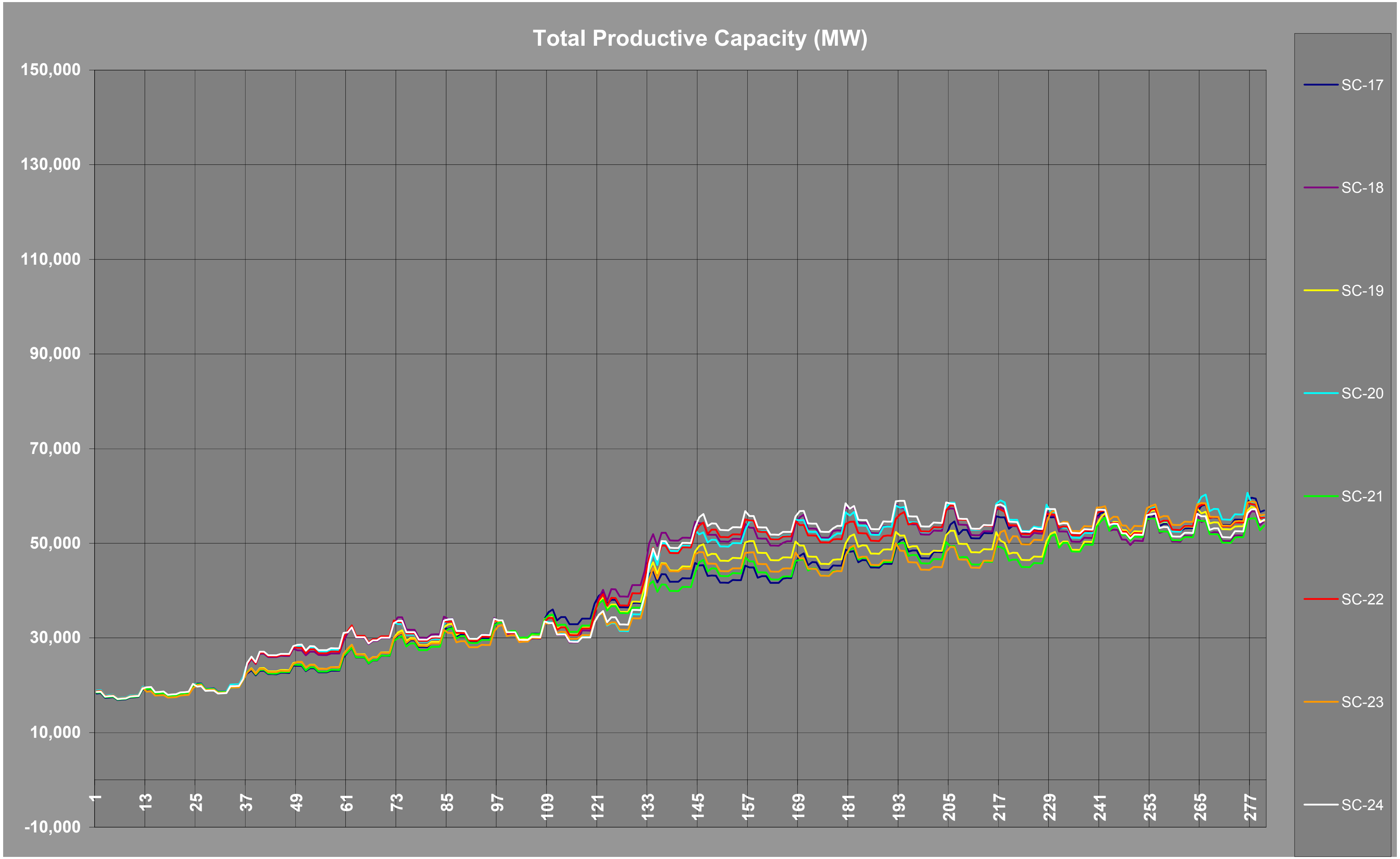

Total Productive Capacity (MW)
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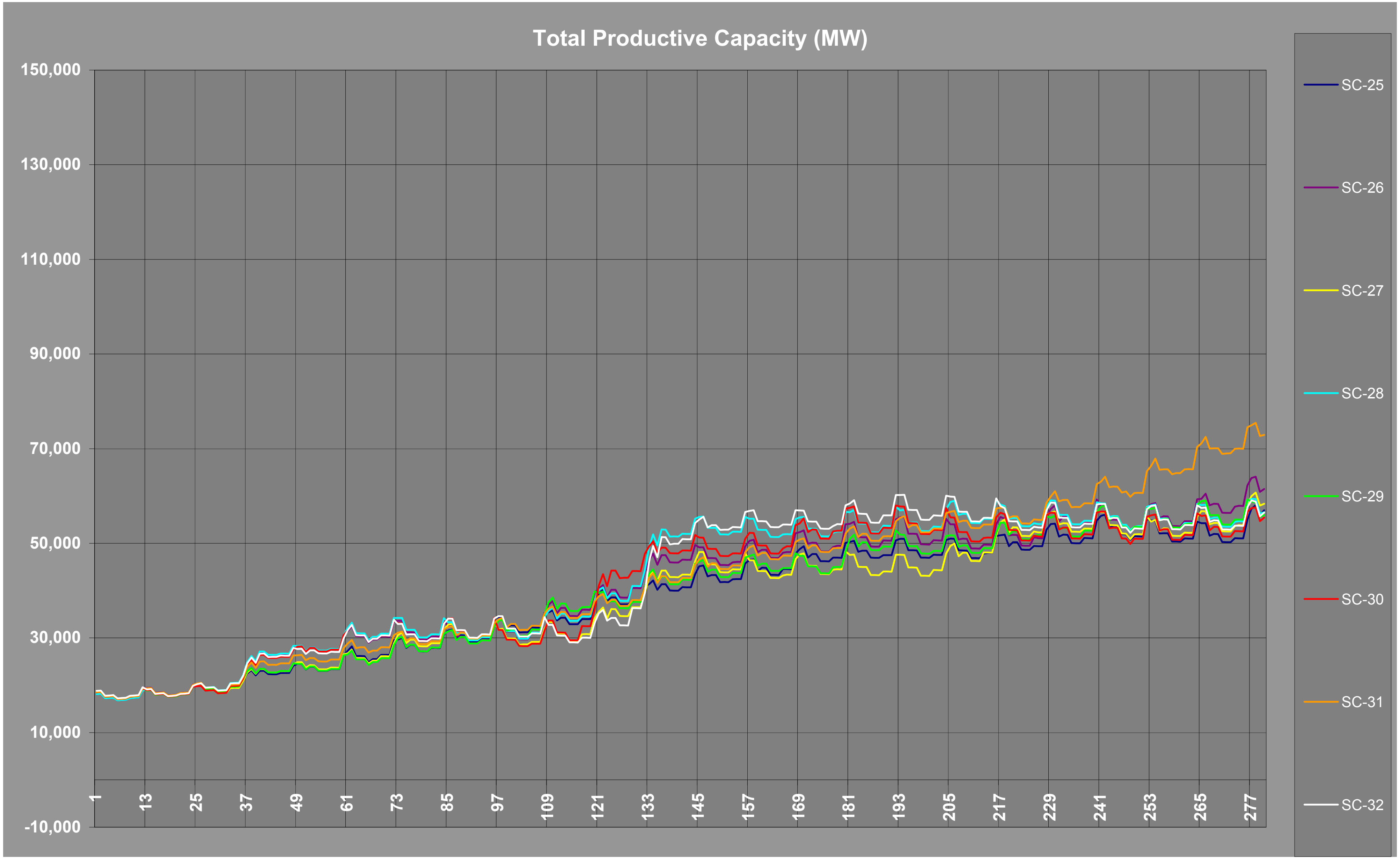

Total Productive Capacity (MW)
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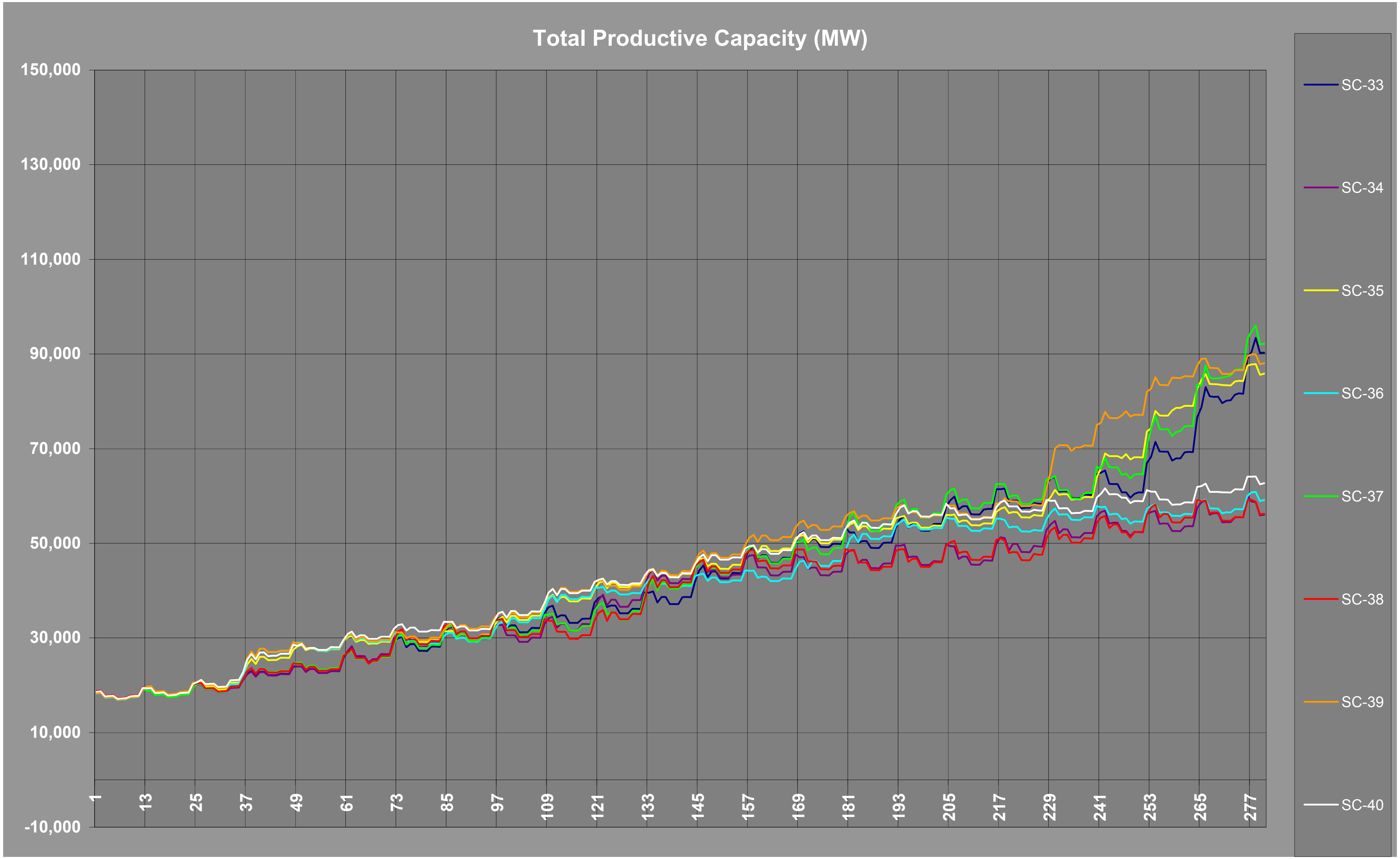

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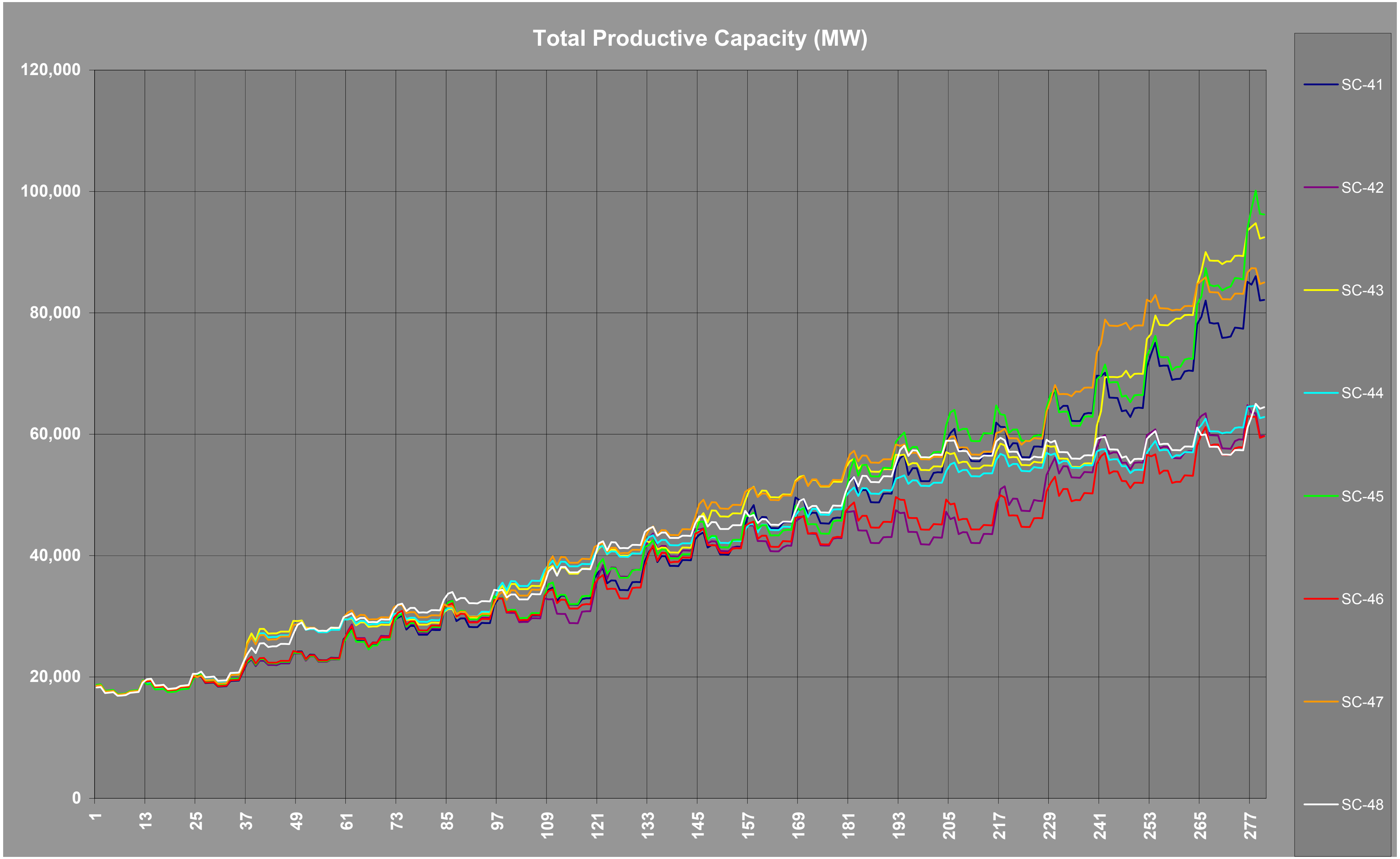
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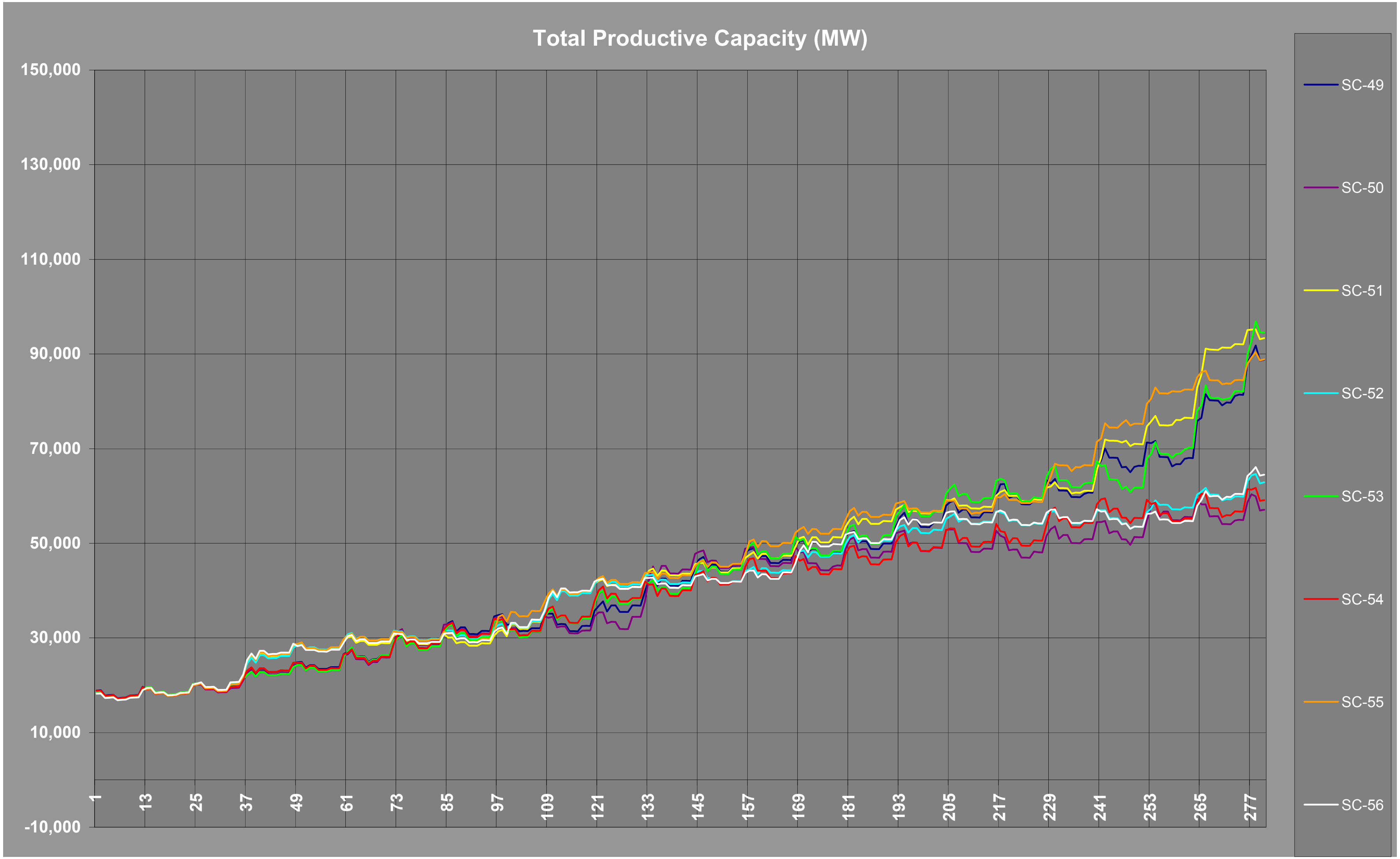

Total Productive Capacity (MW)
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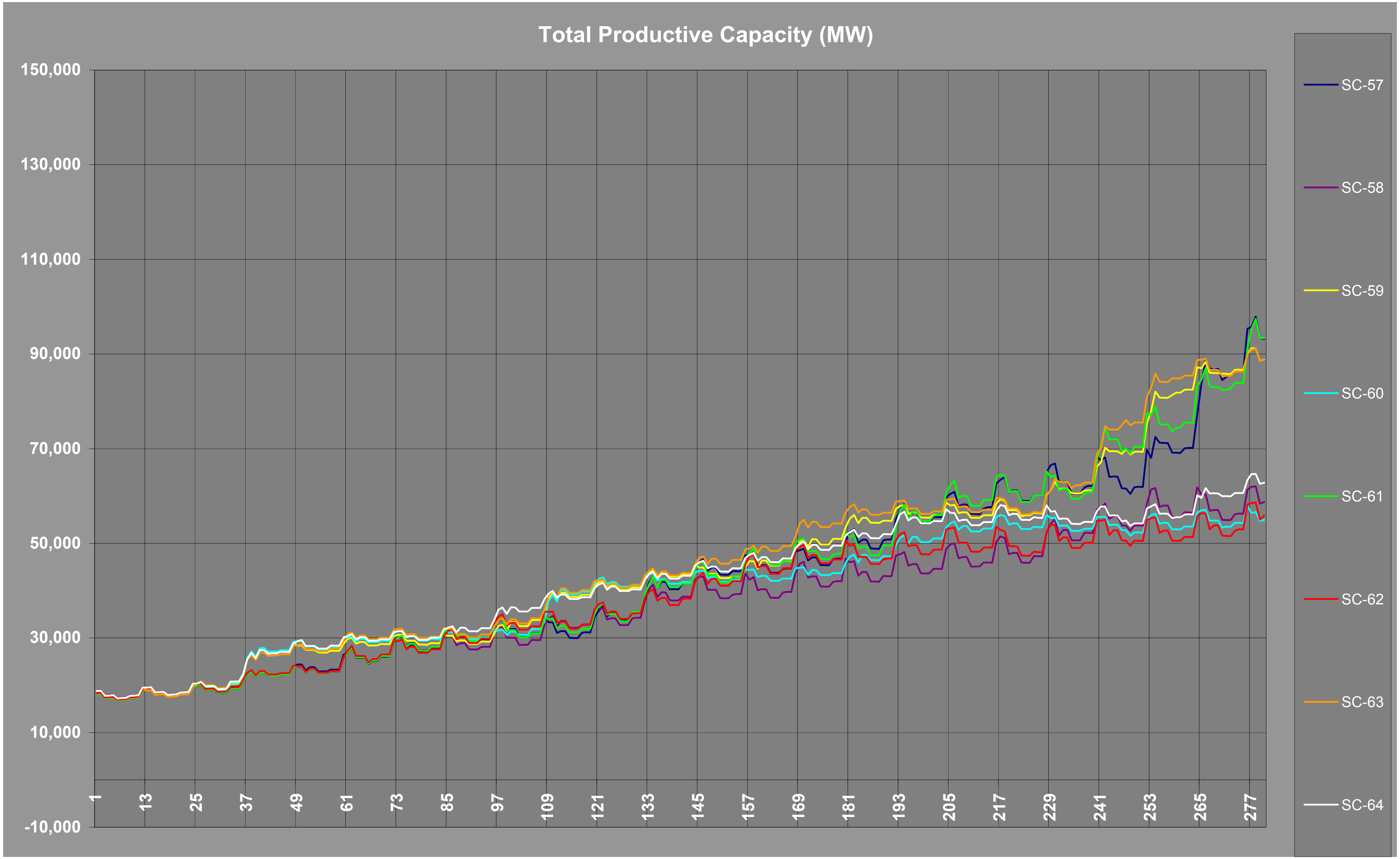
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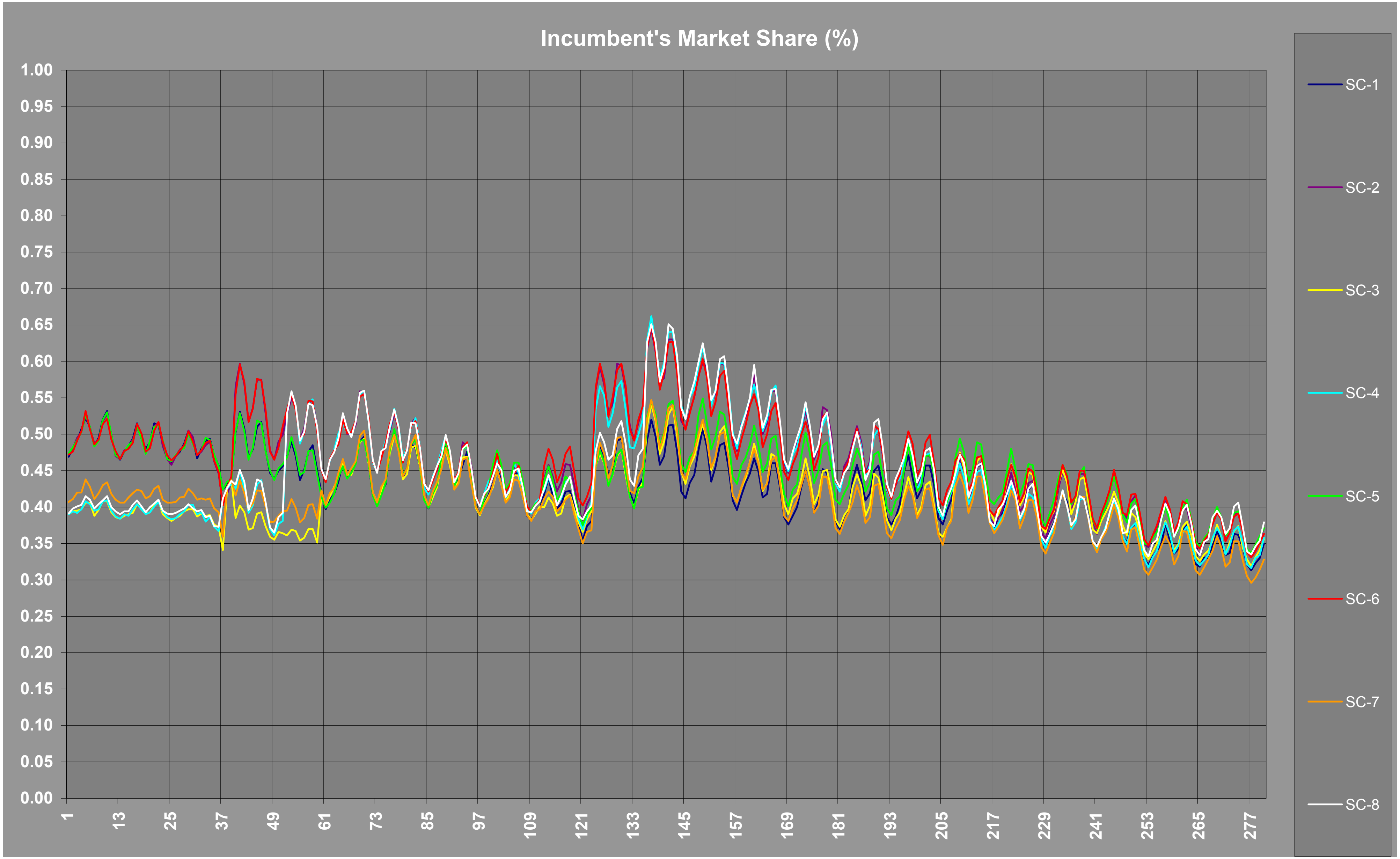
Incumbent's Market Share (%)
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0.80
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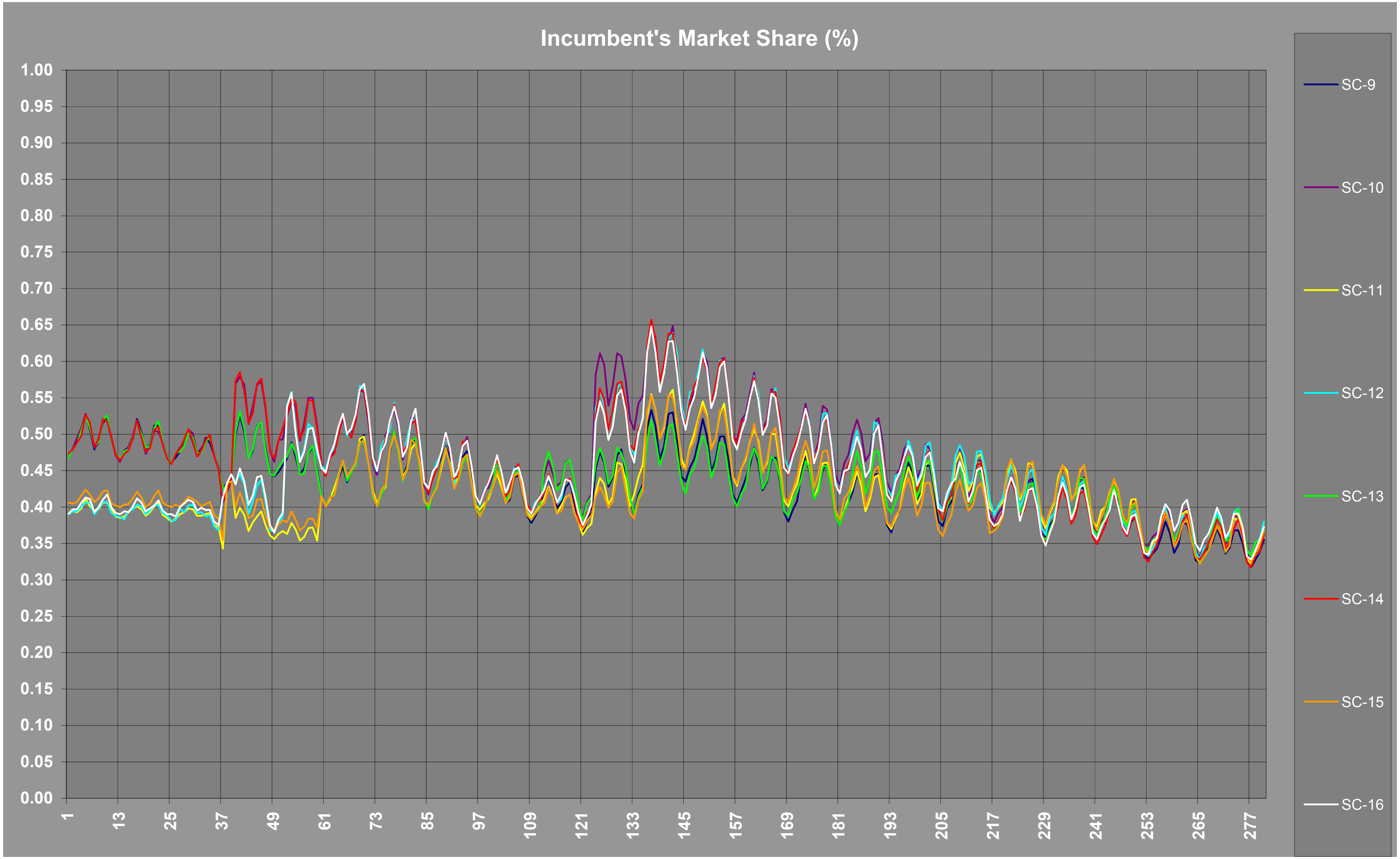

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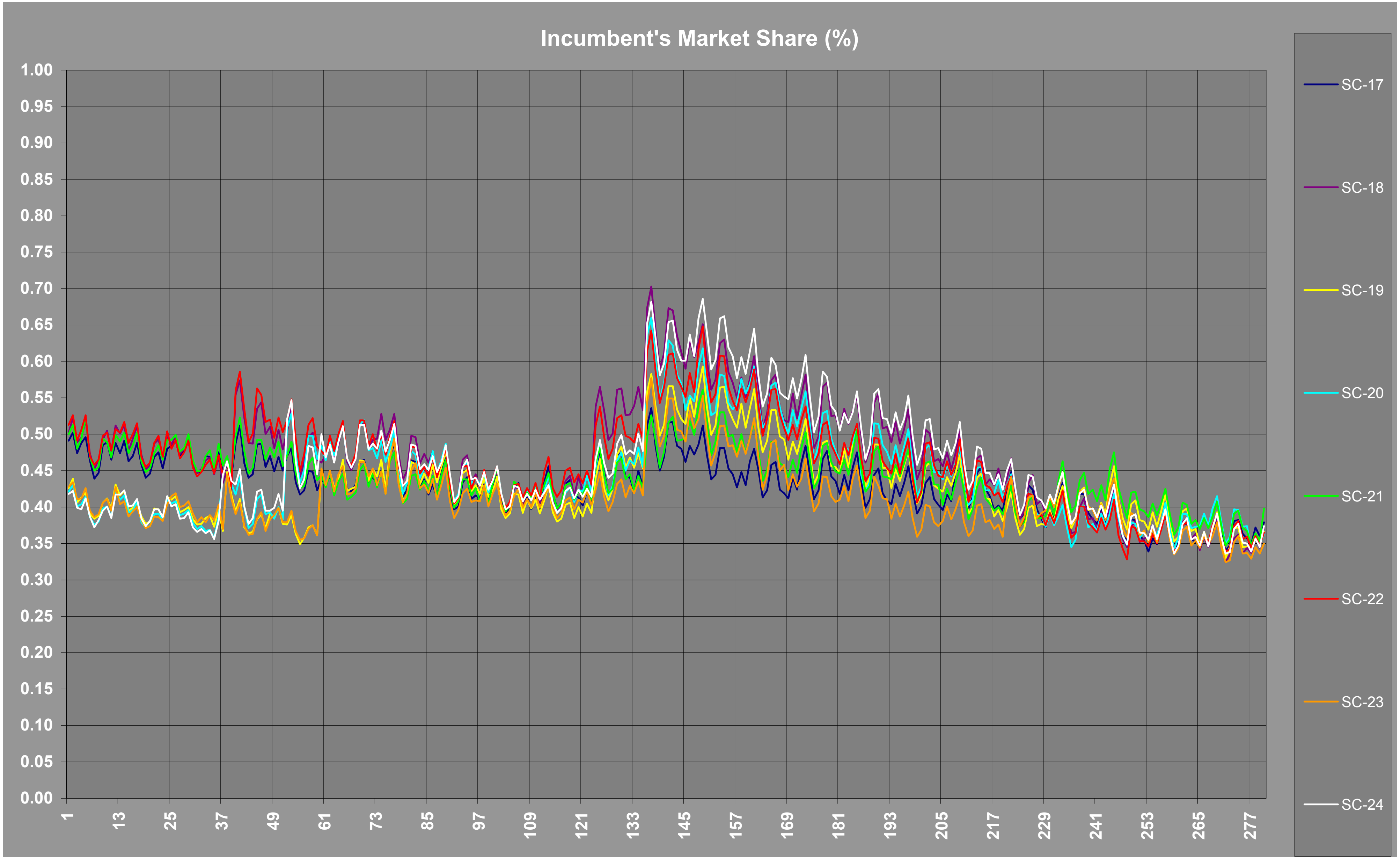

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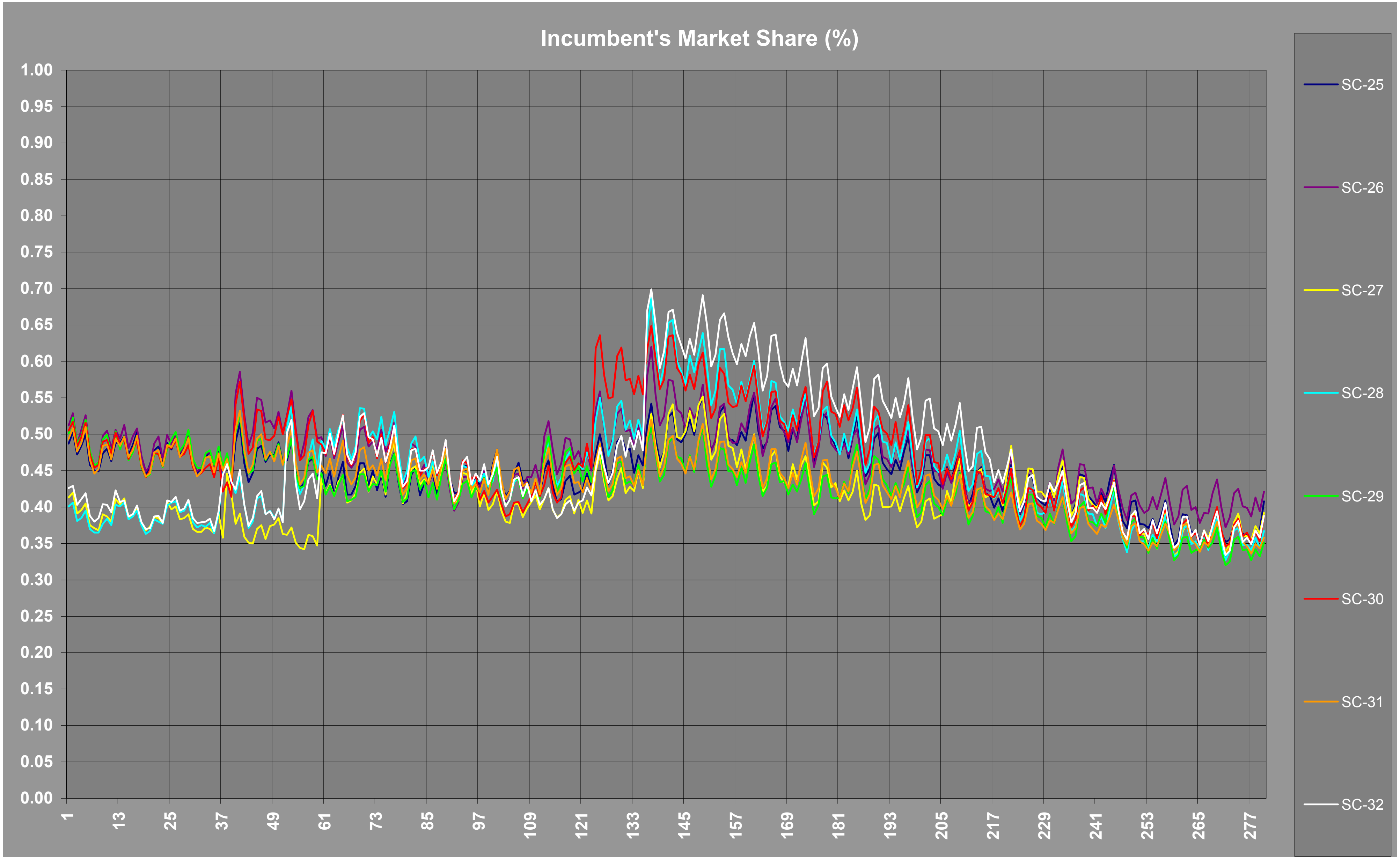
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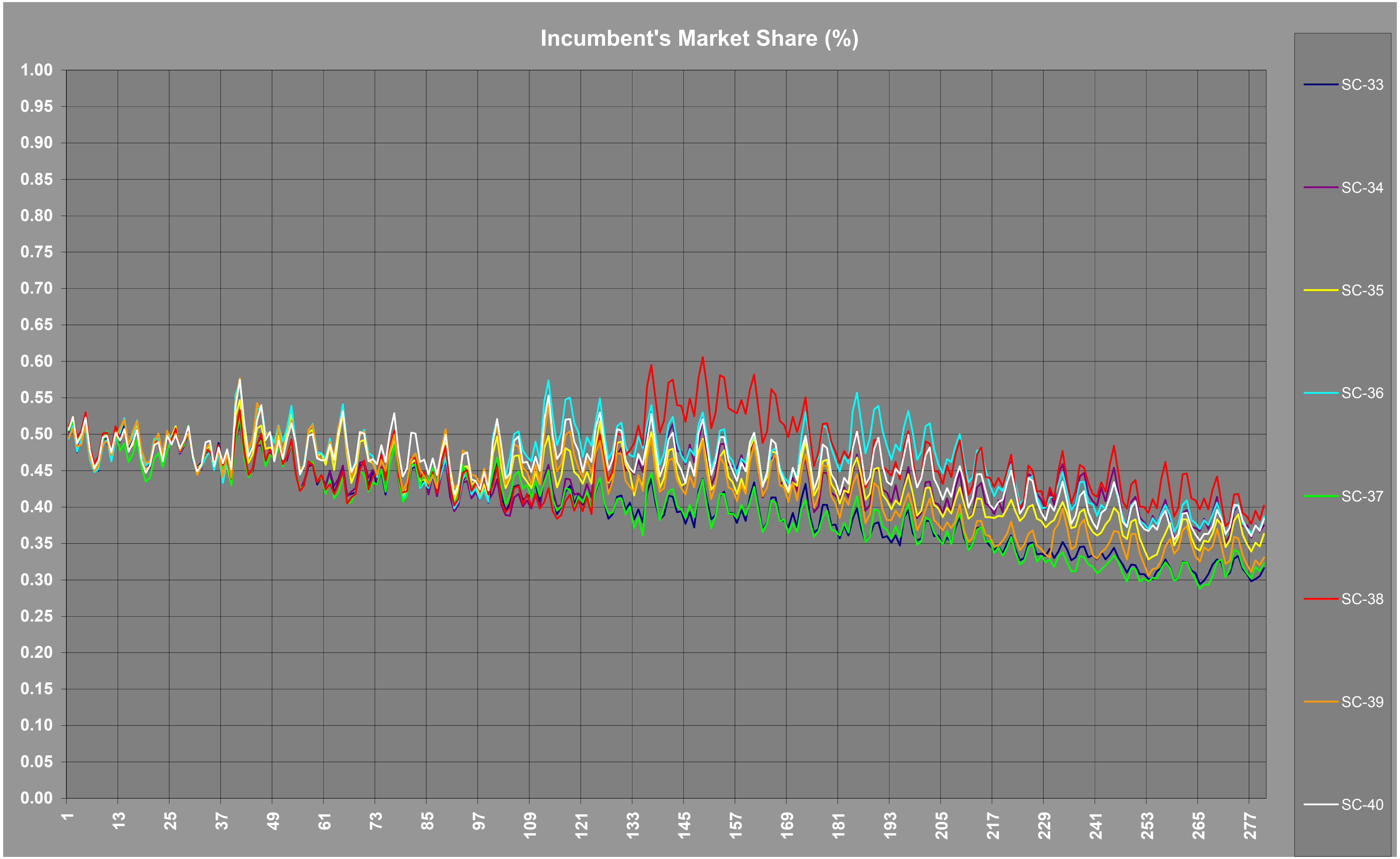

Incumbent's Market Share (%)
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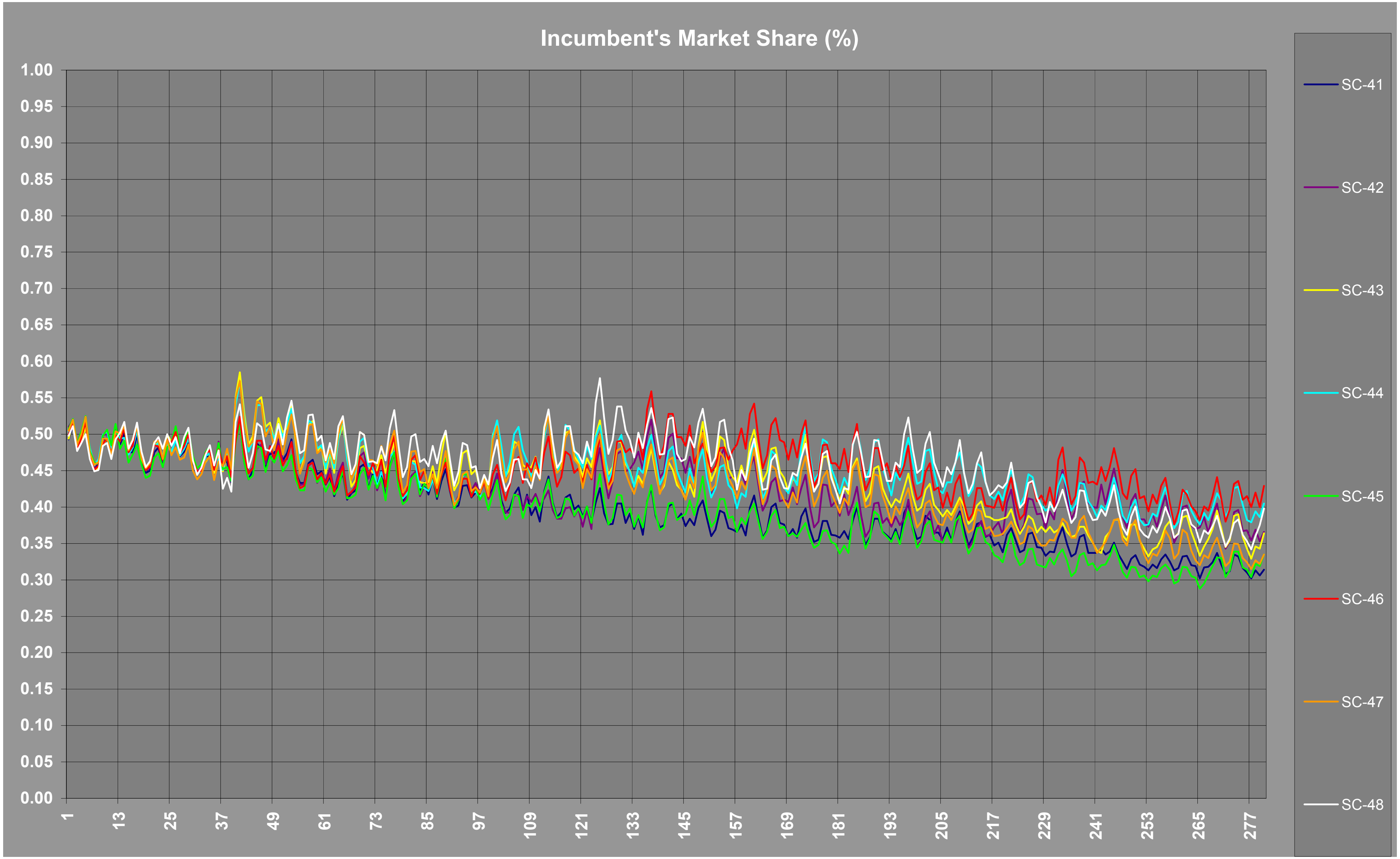

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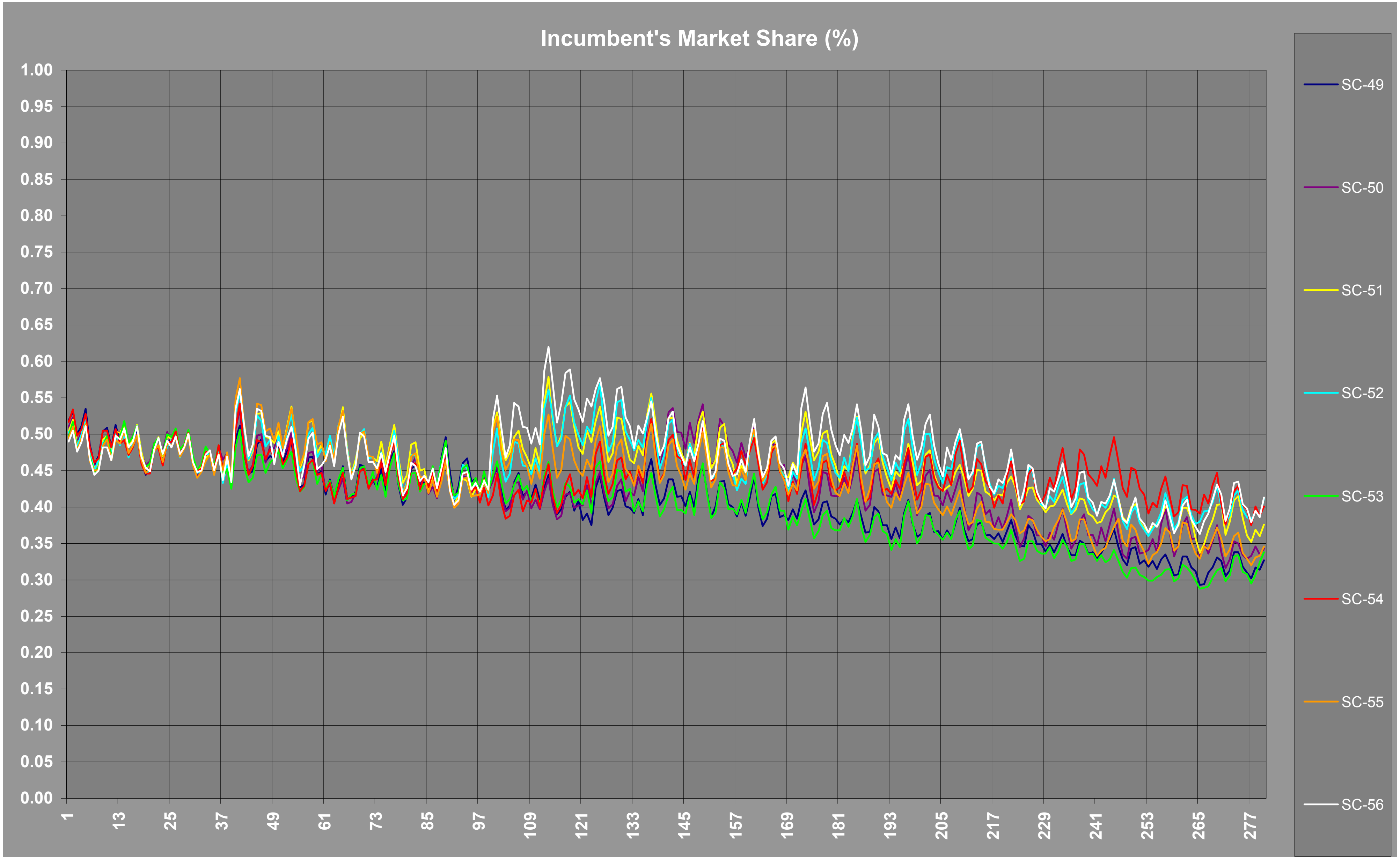
Incumbent's Market Share (%)
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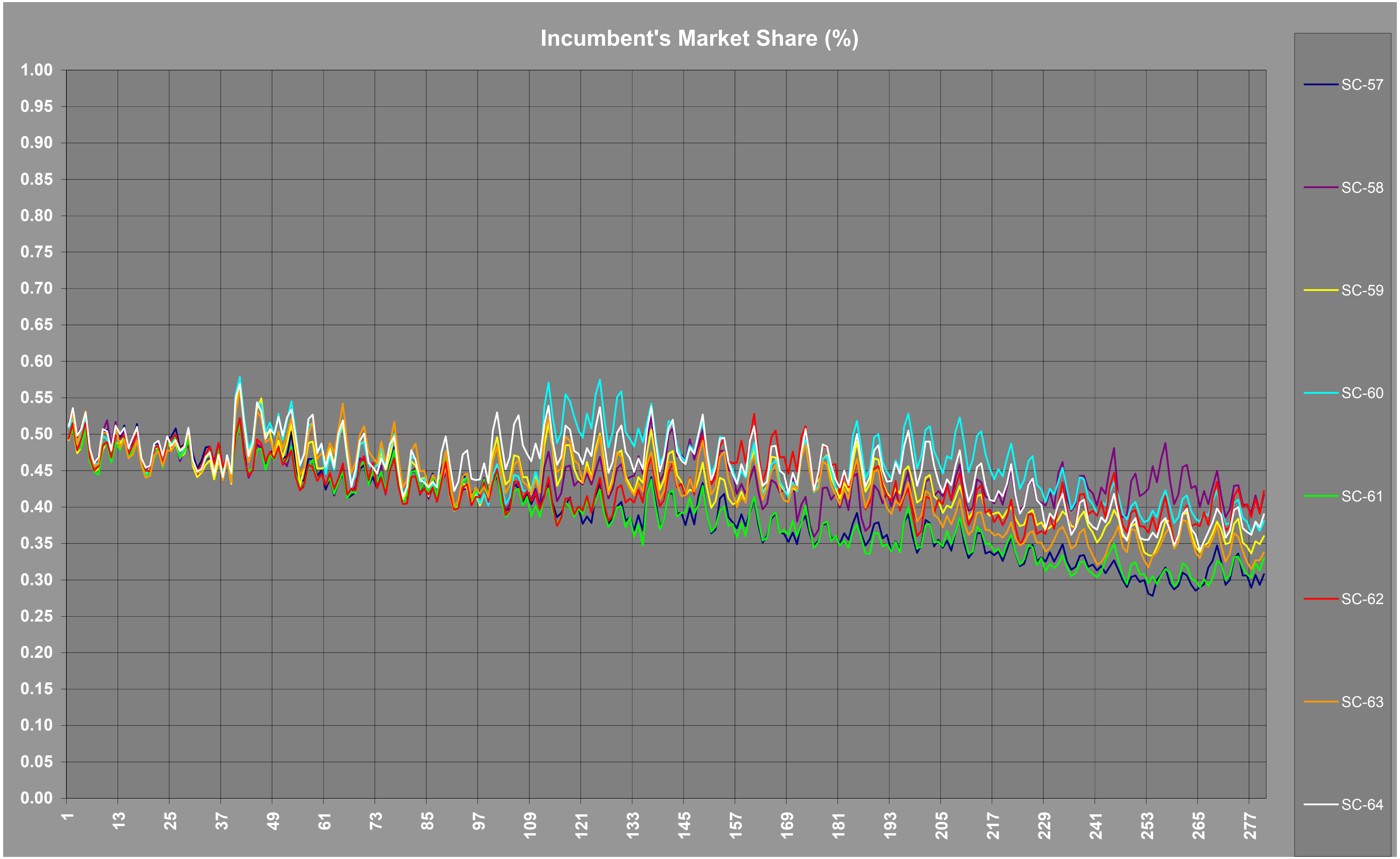

Incumbent's Market Share (%)
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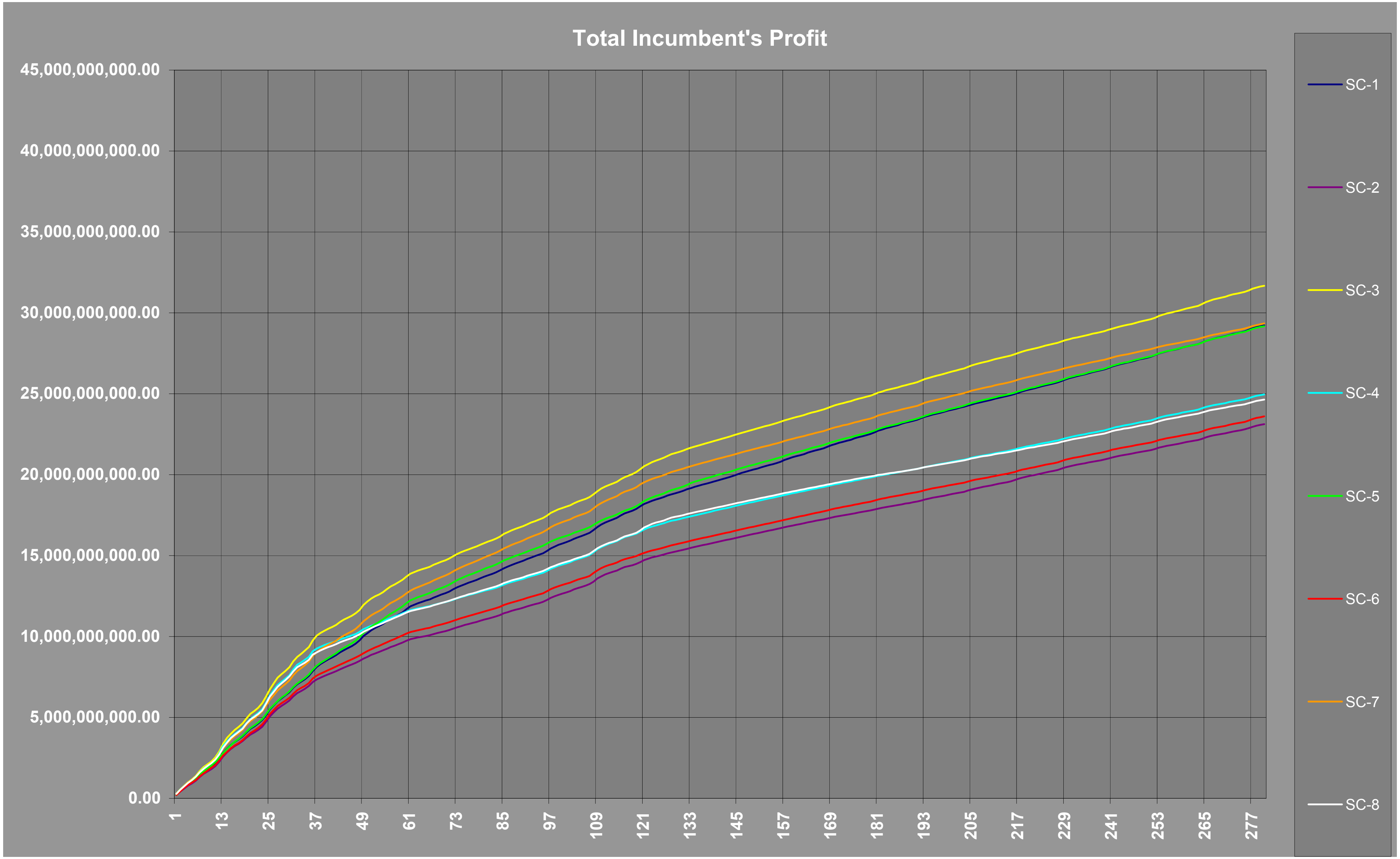
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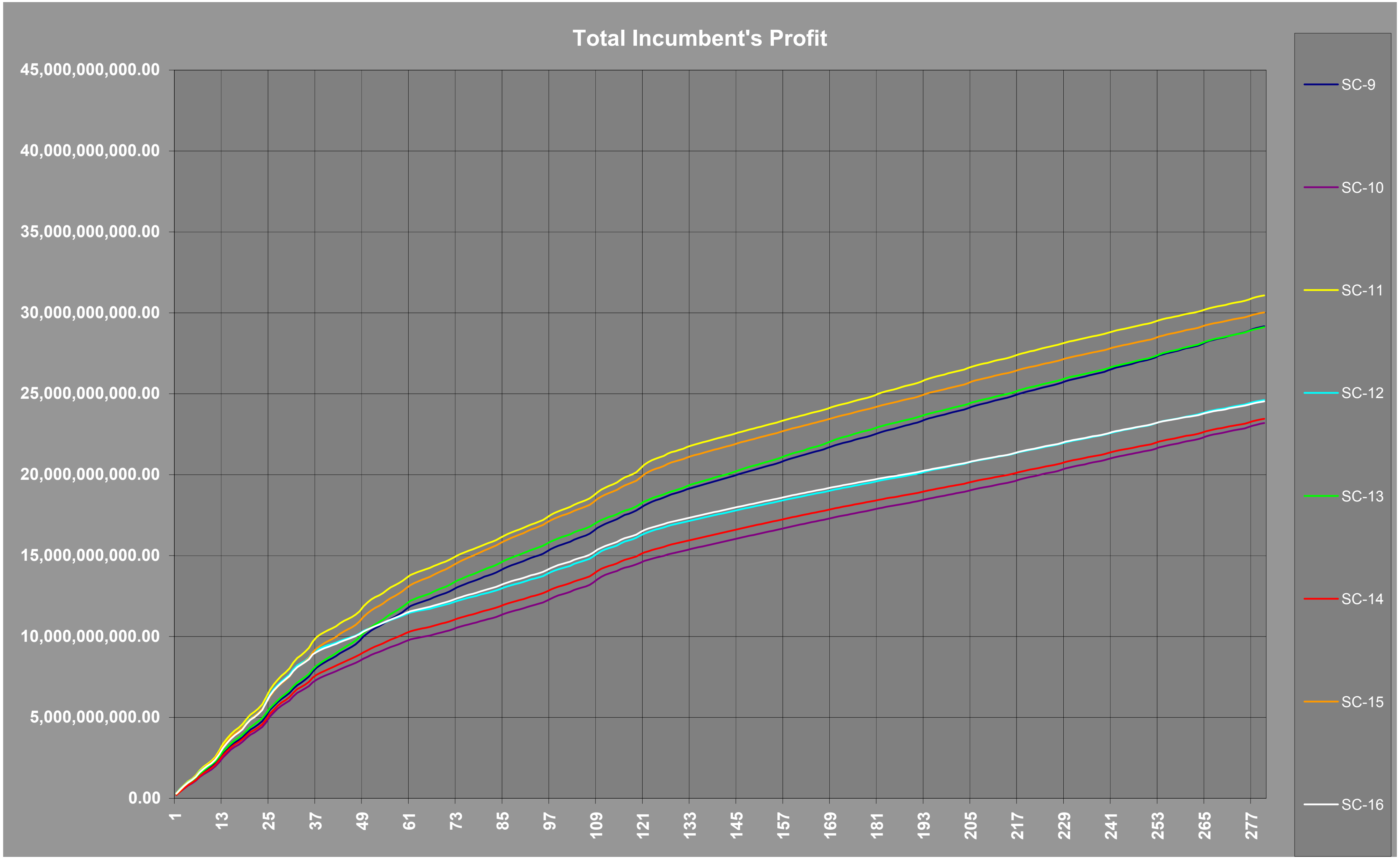

Total Incumbent's Profit
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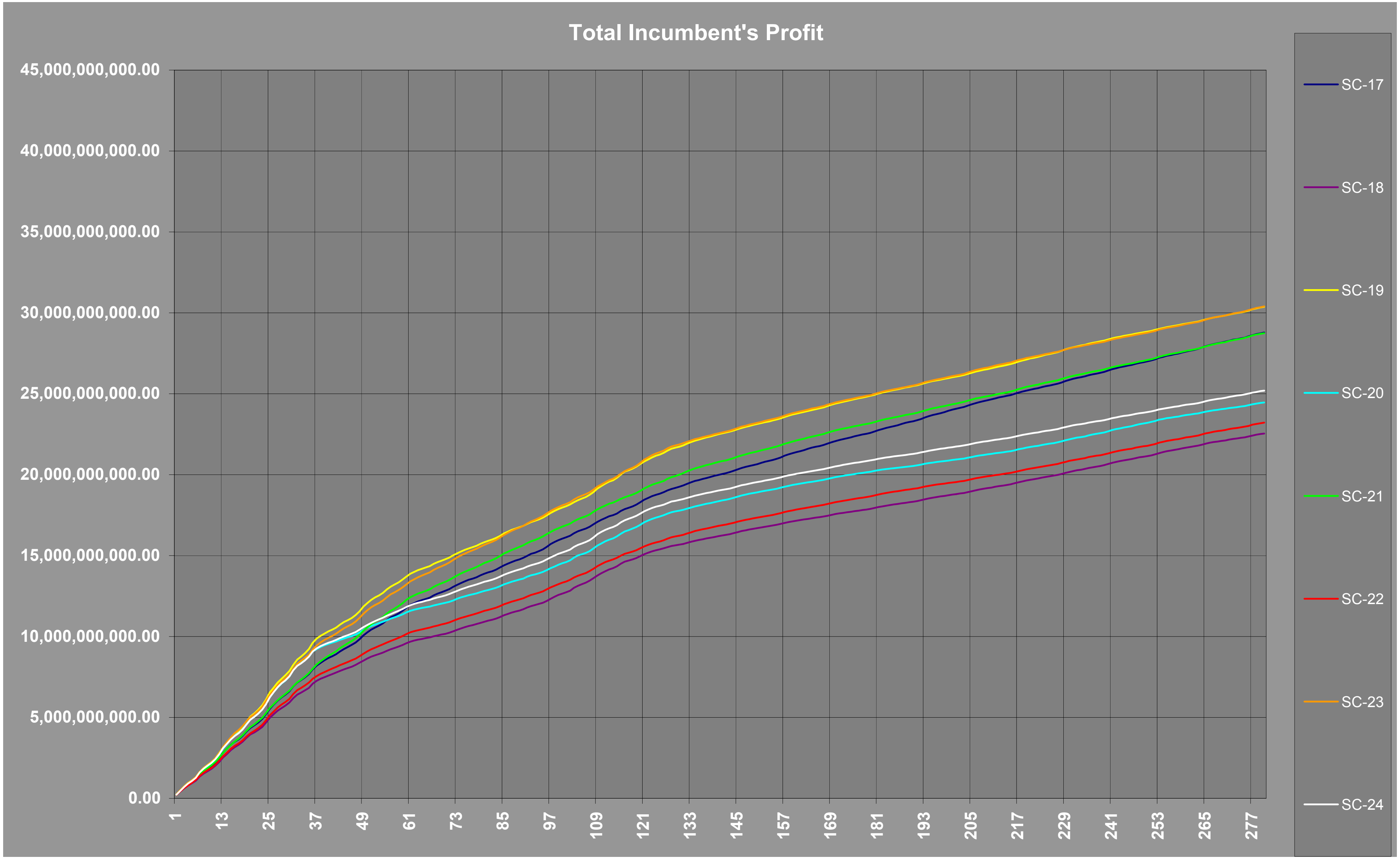
Total Incumbent's Profit
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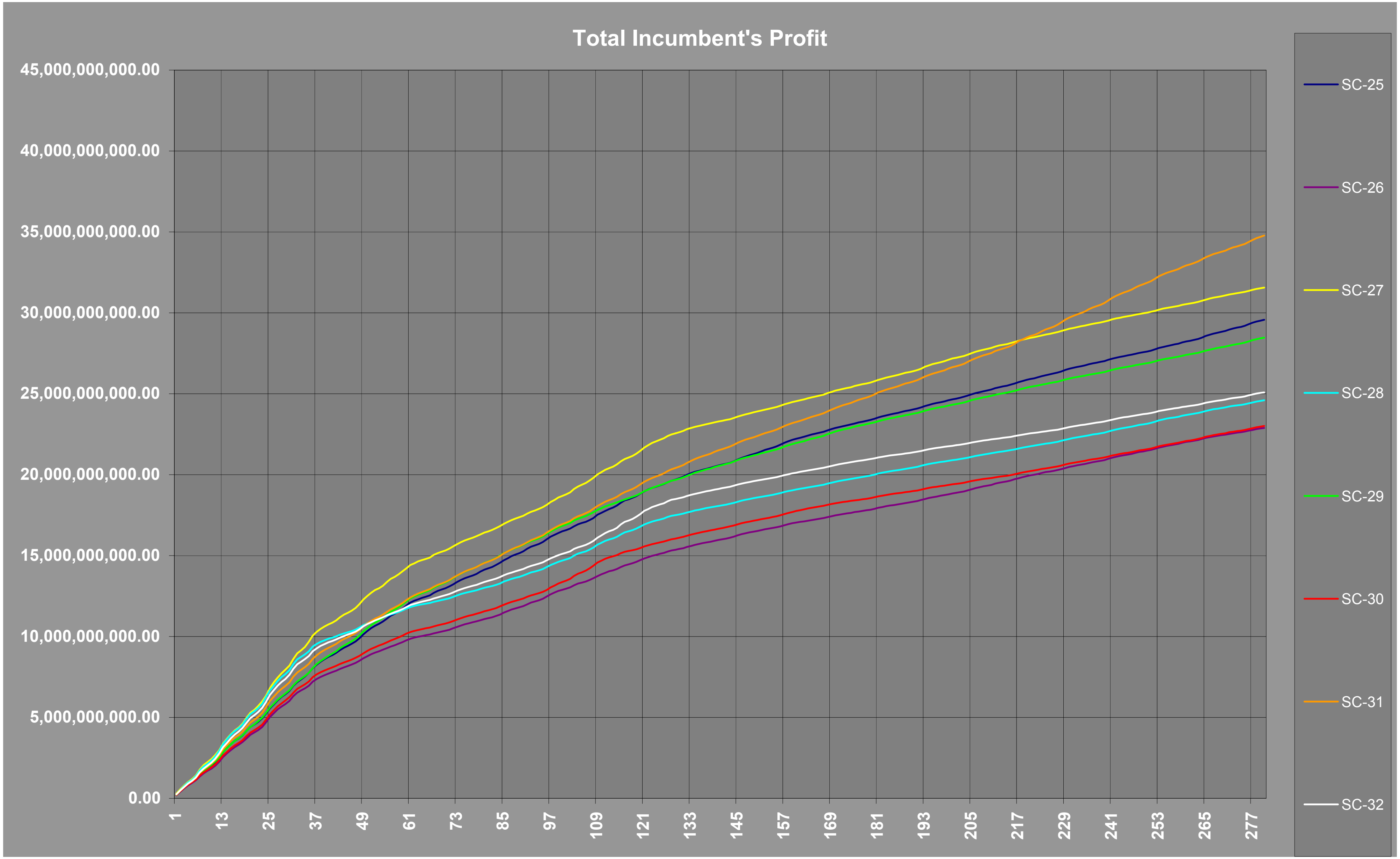
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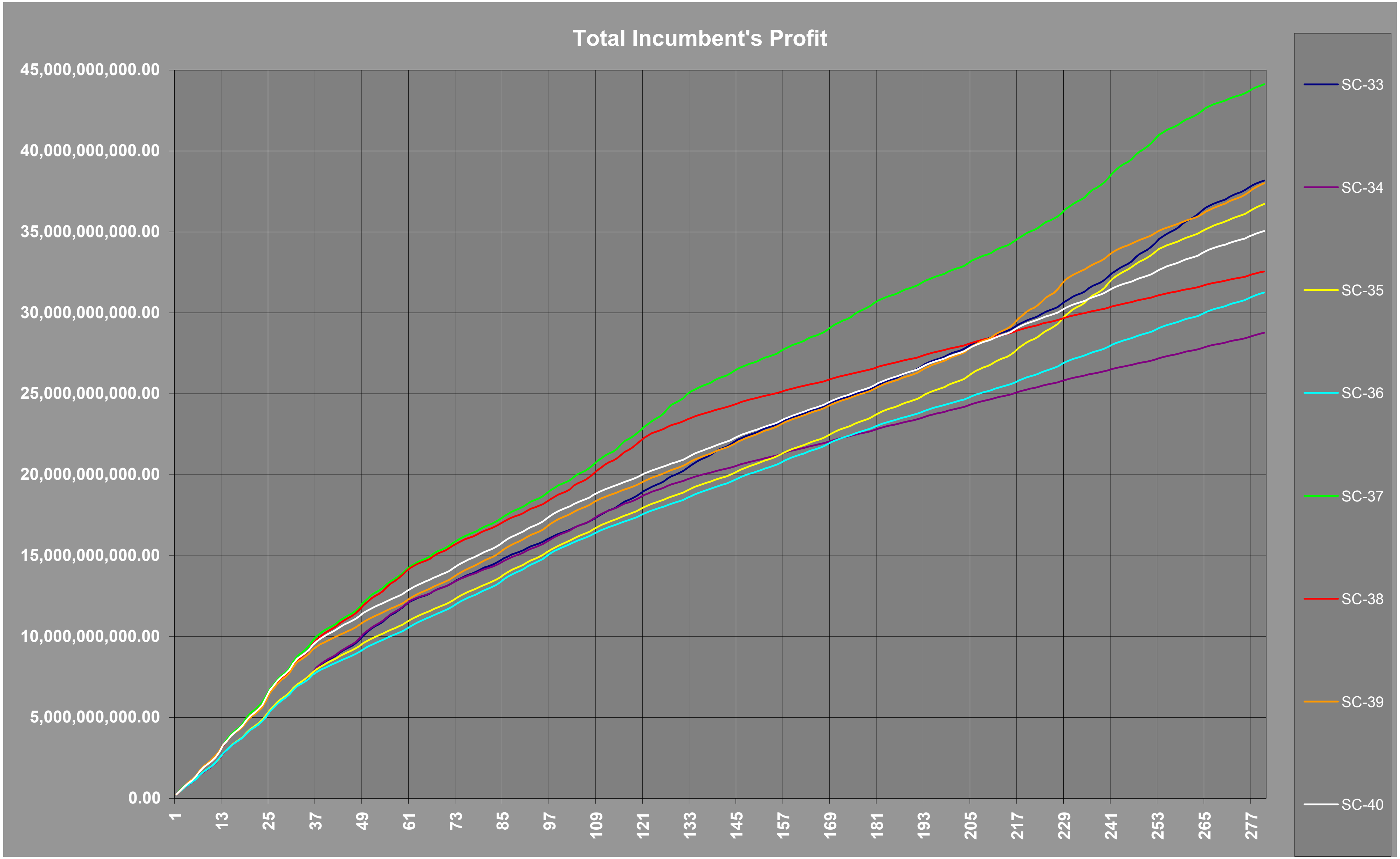
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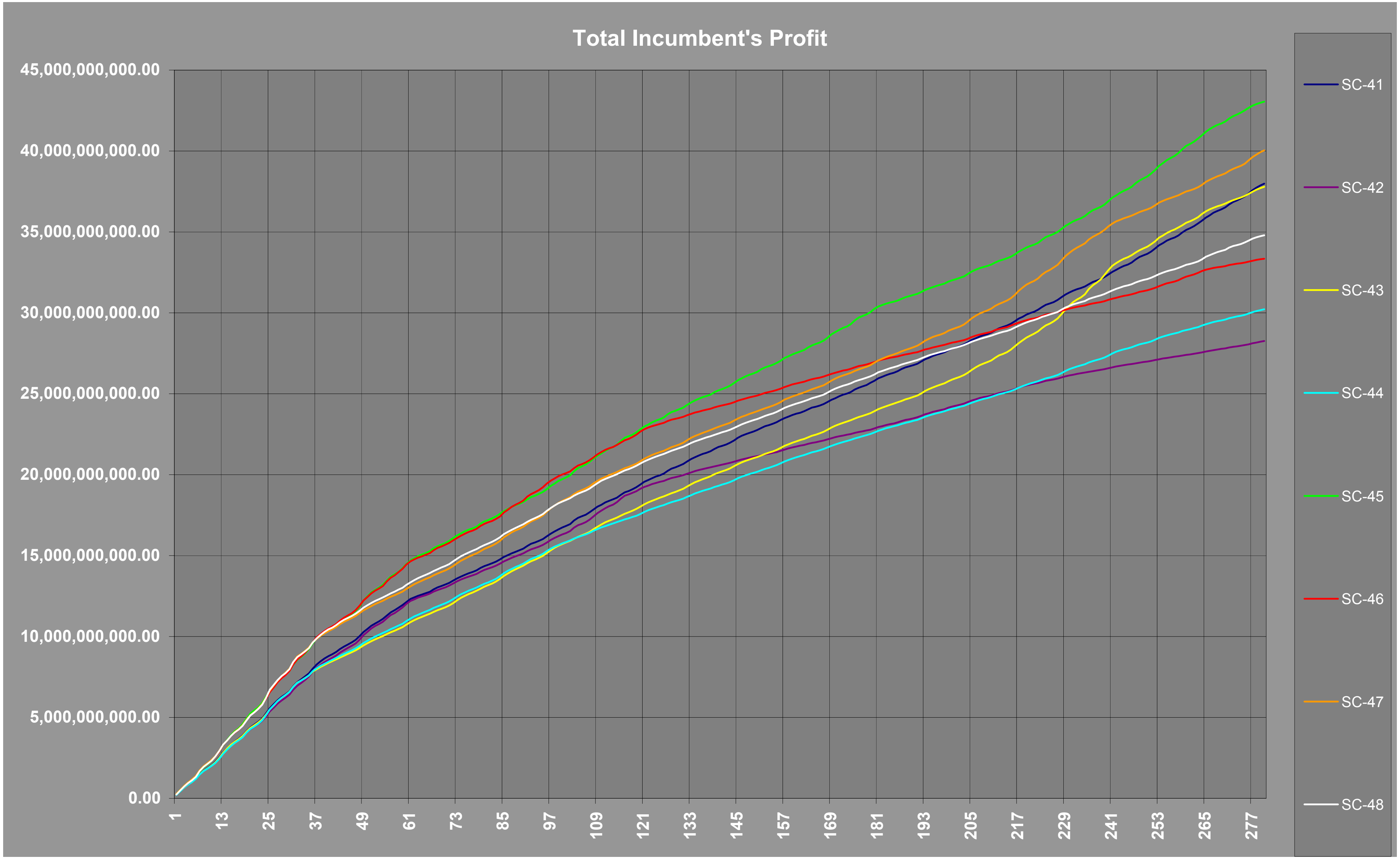
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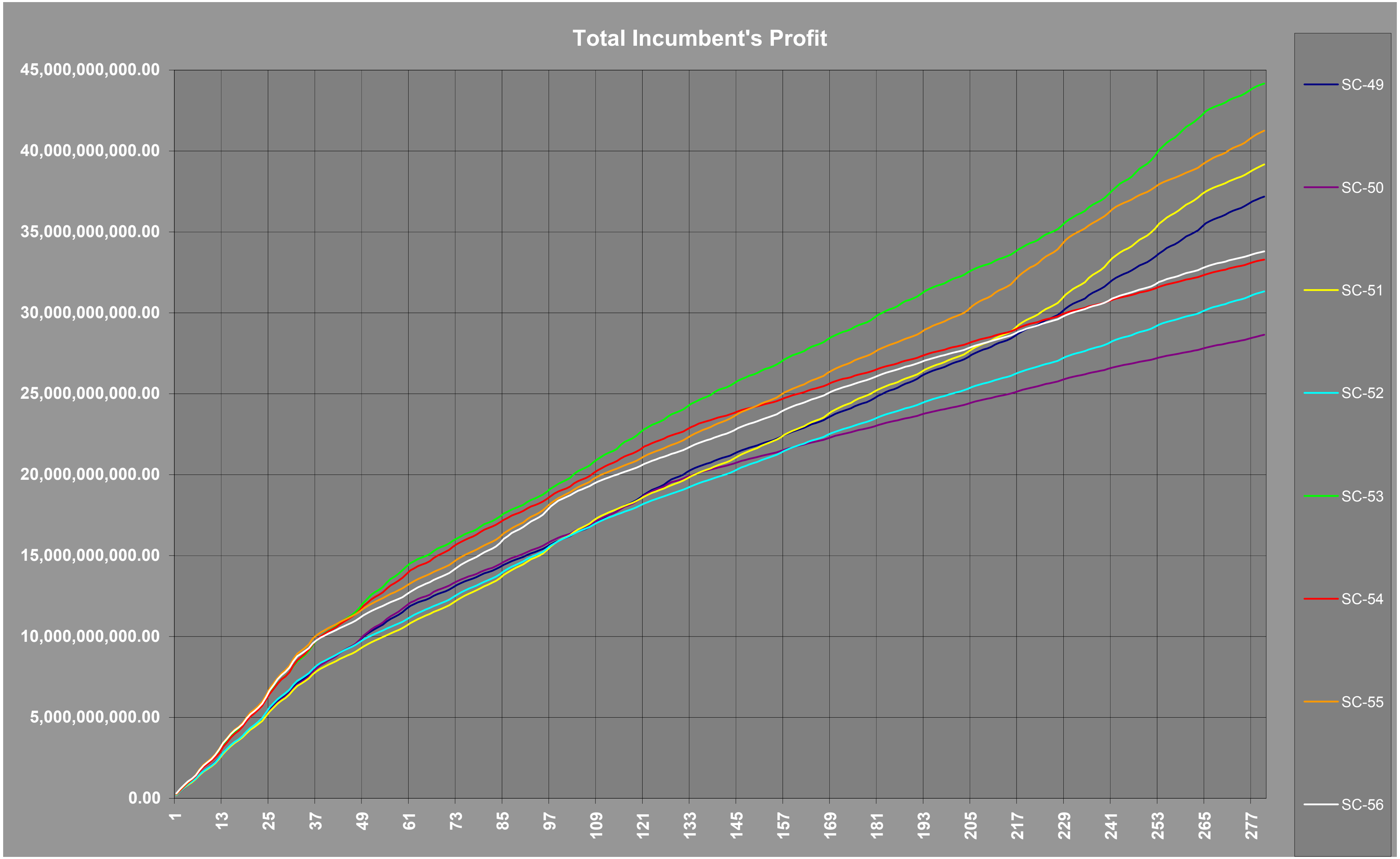

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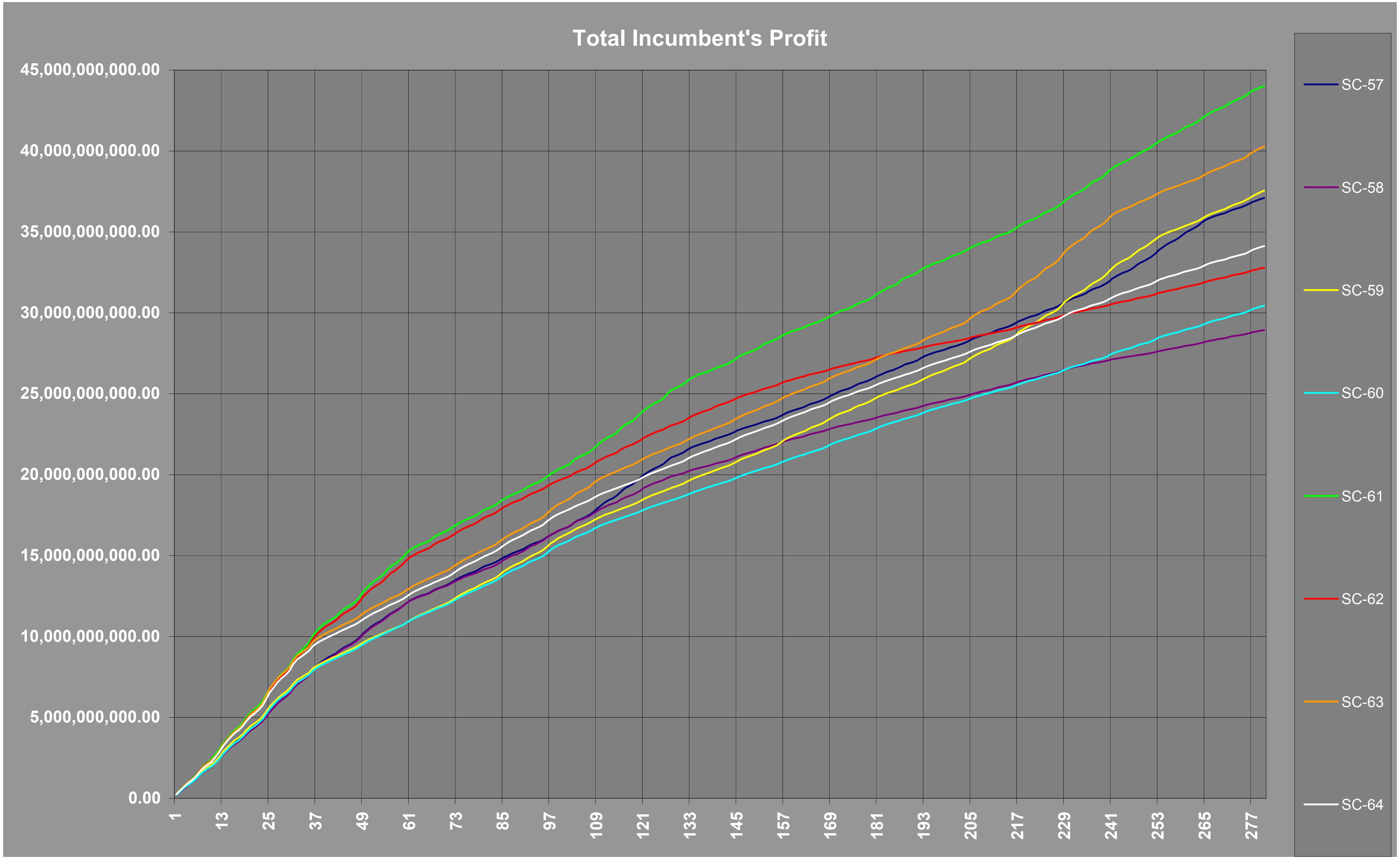
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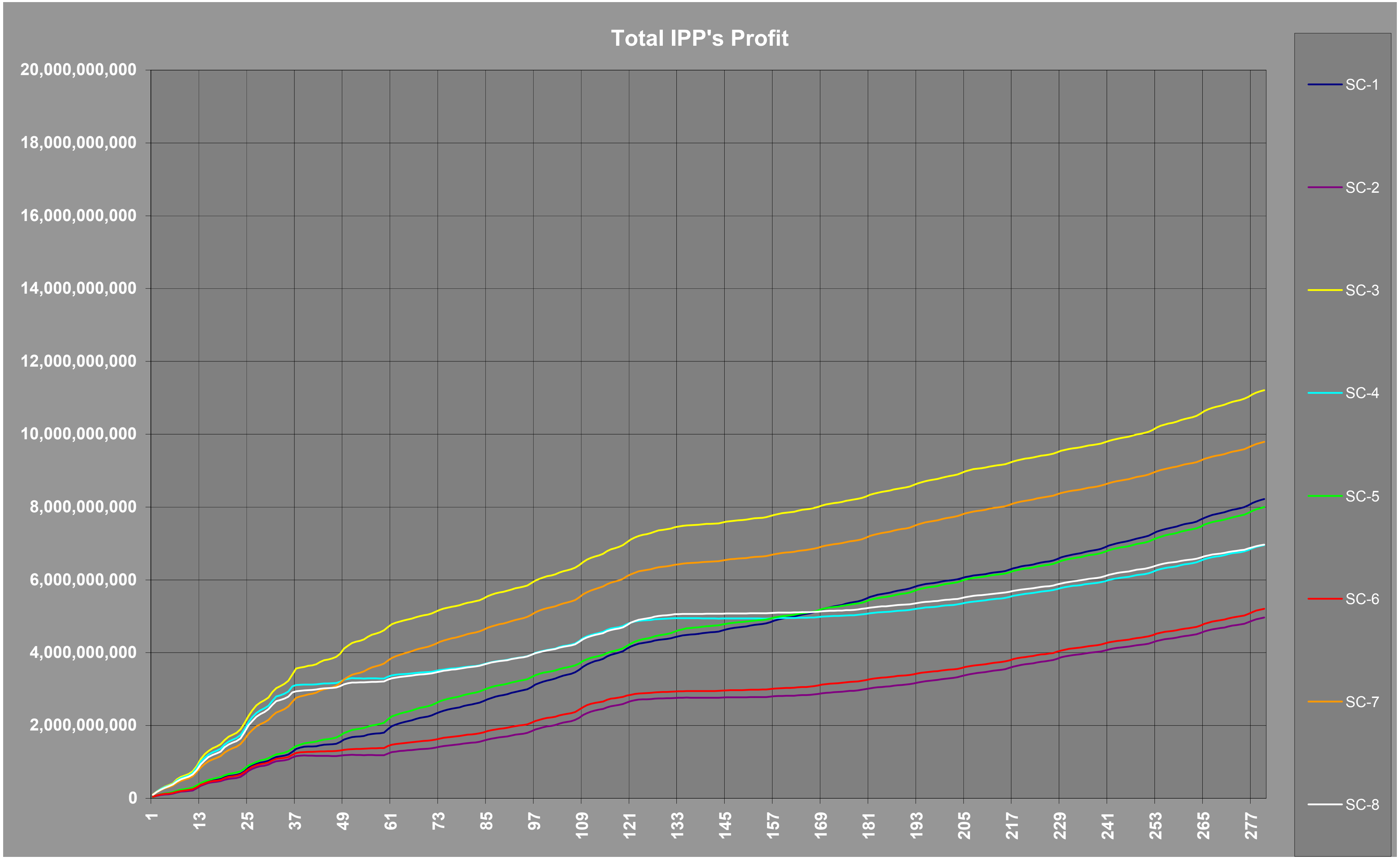

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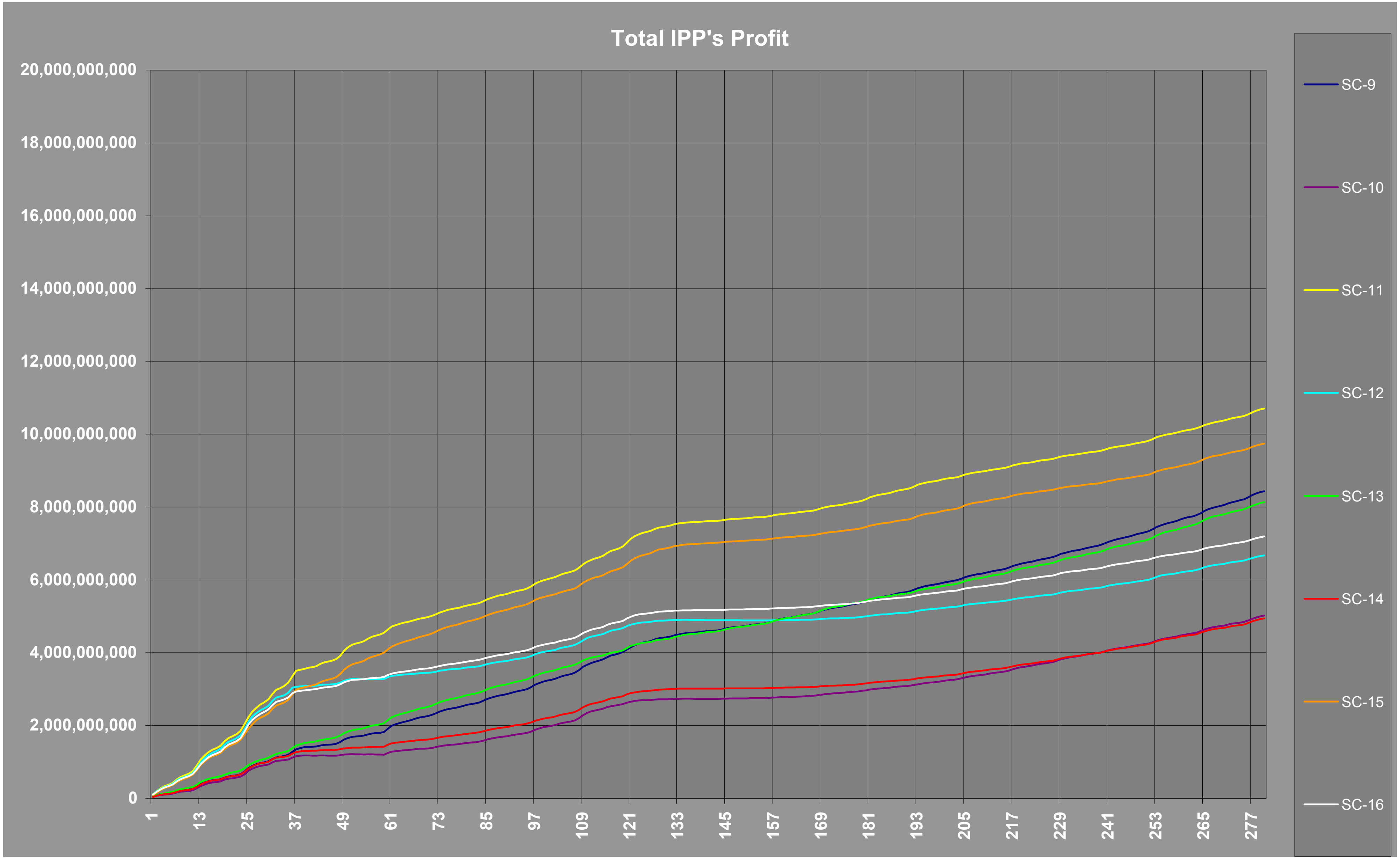

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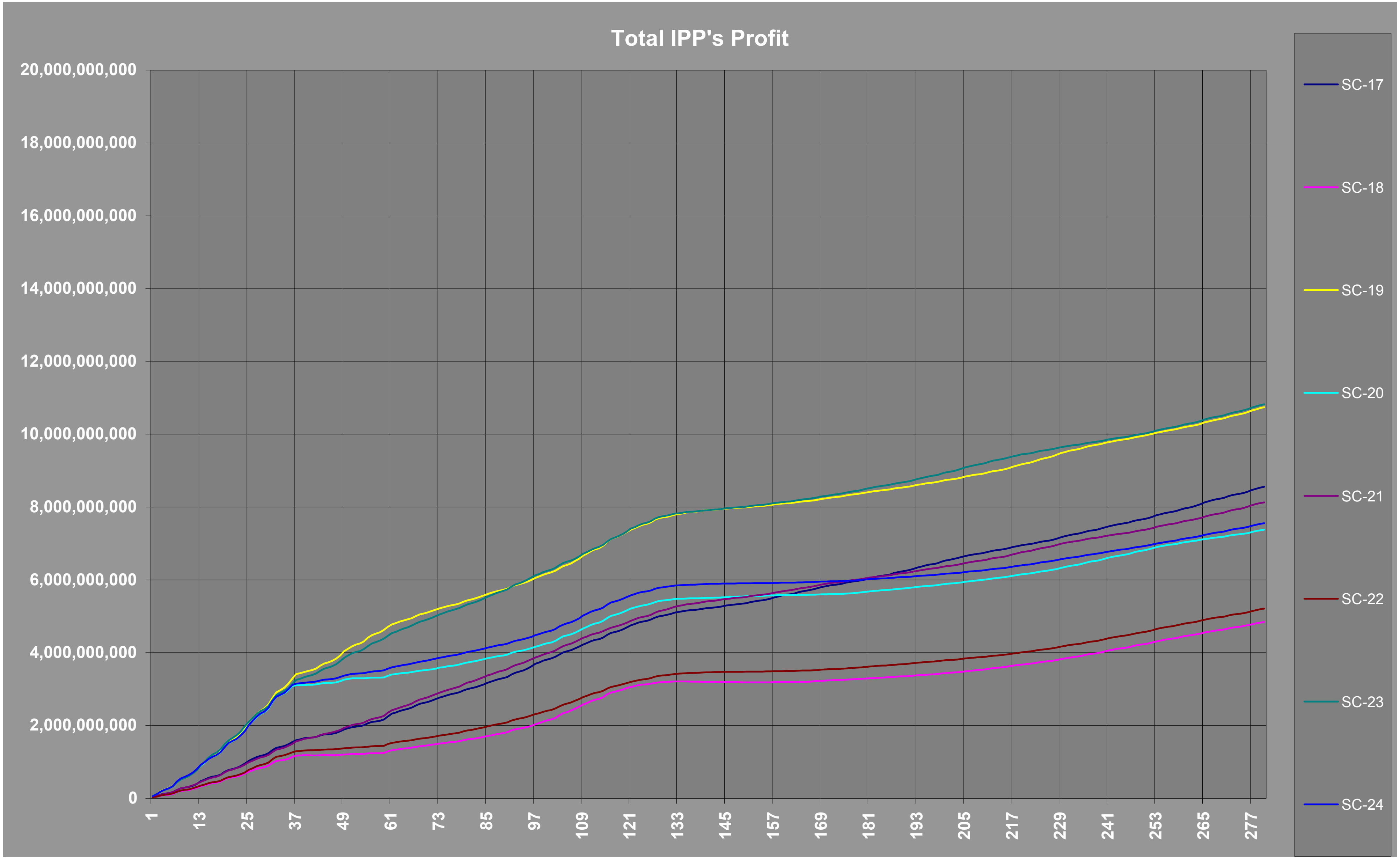
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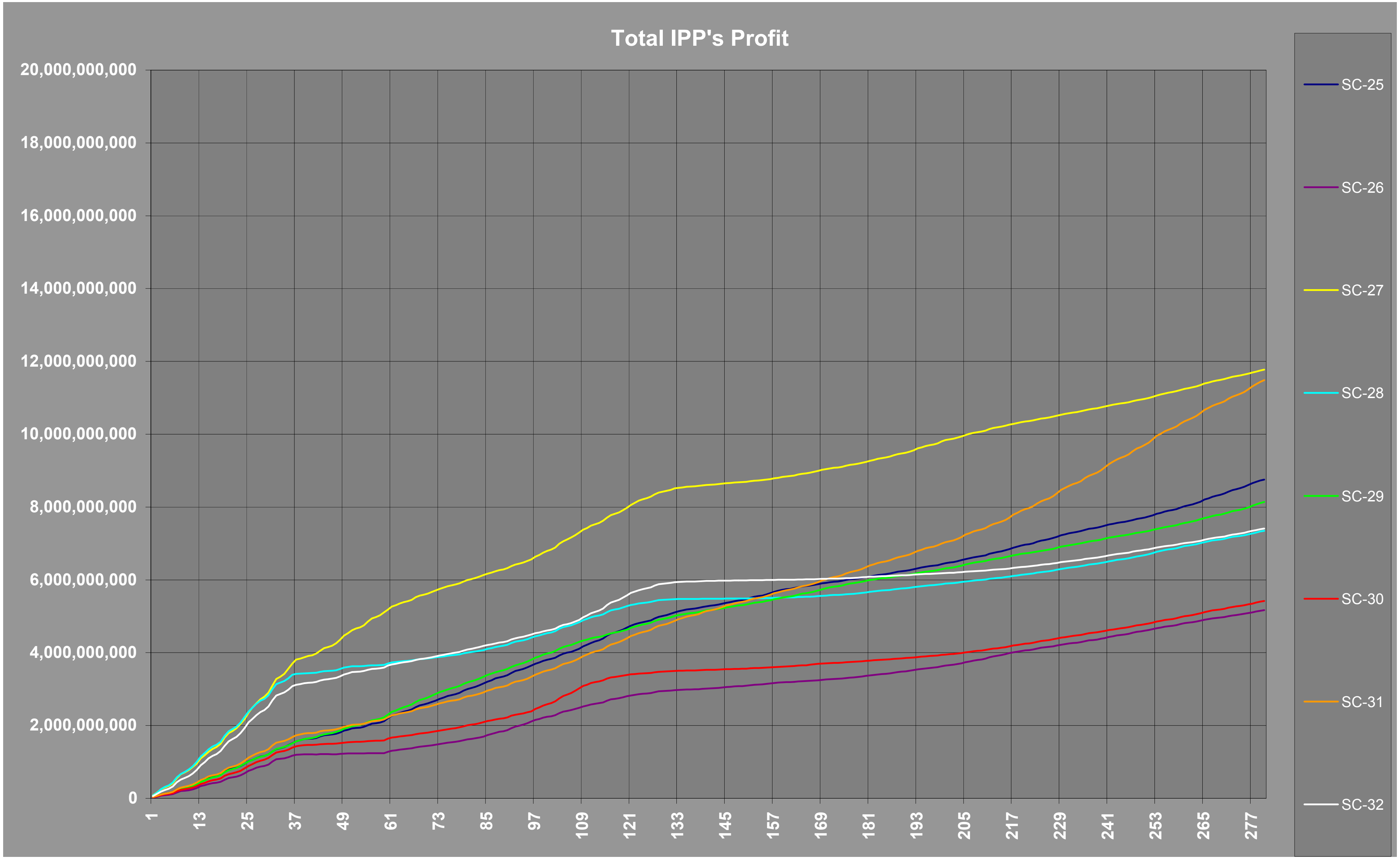
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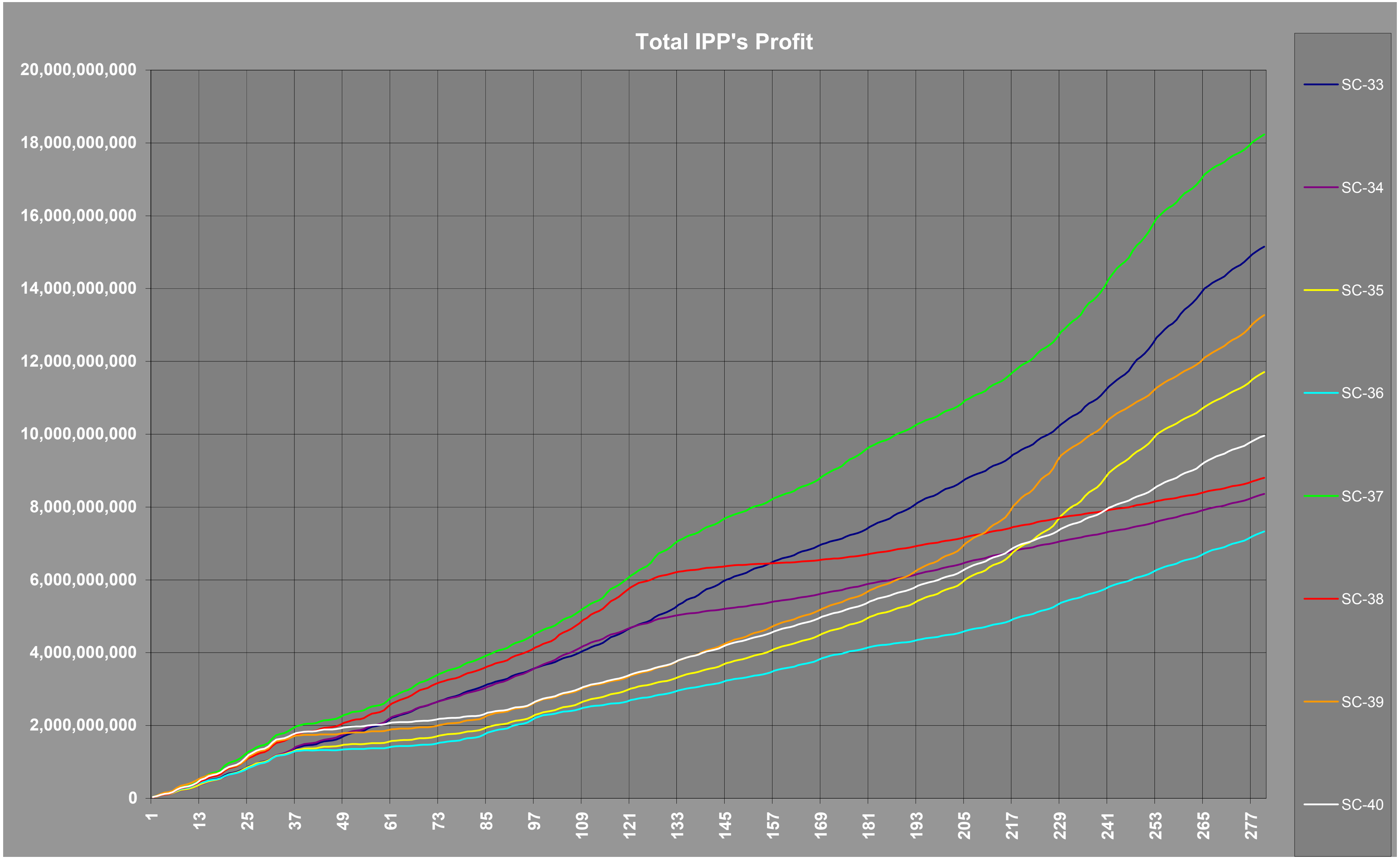

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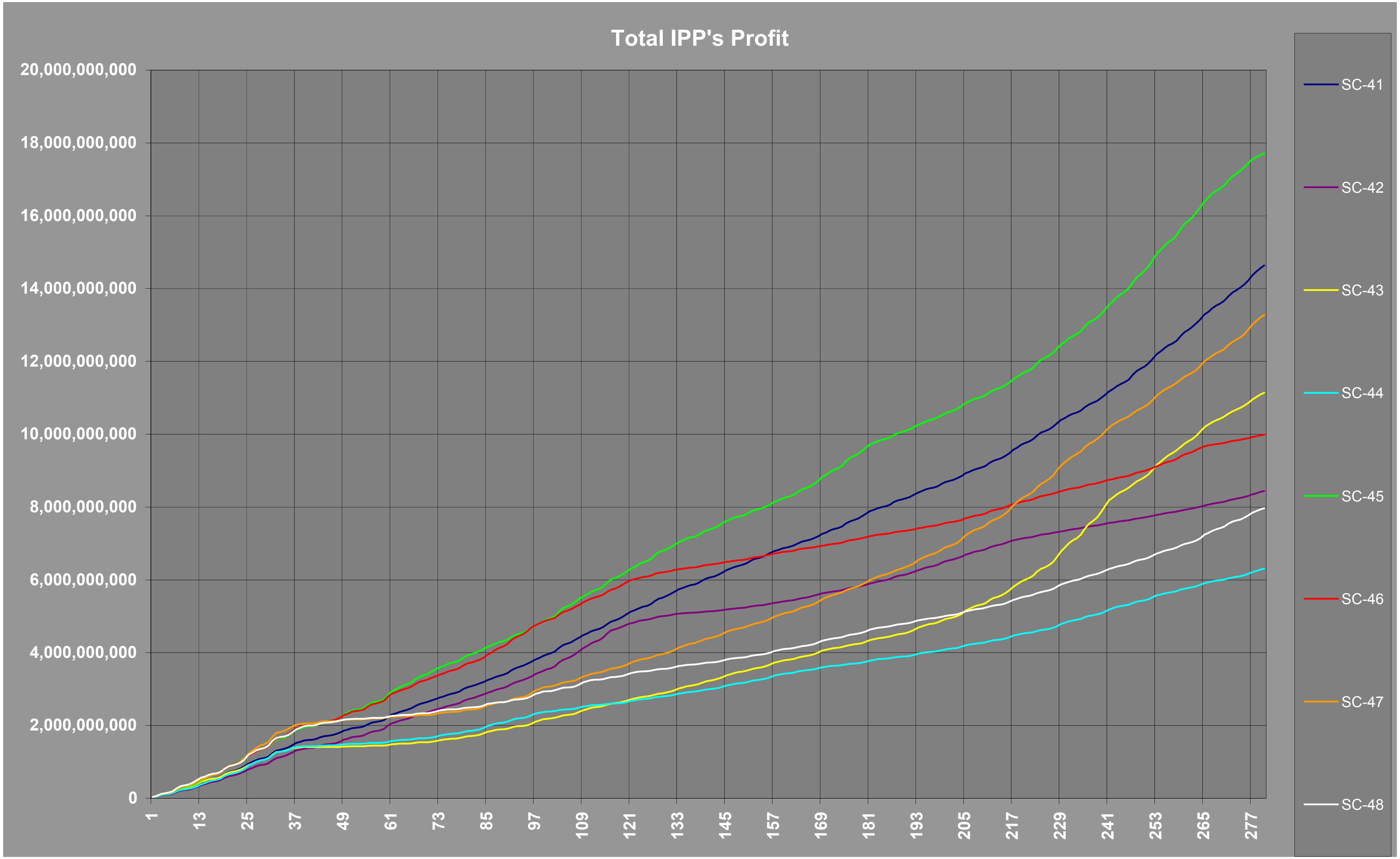
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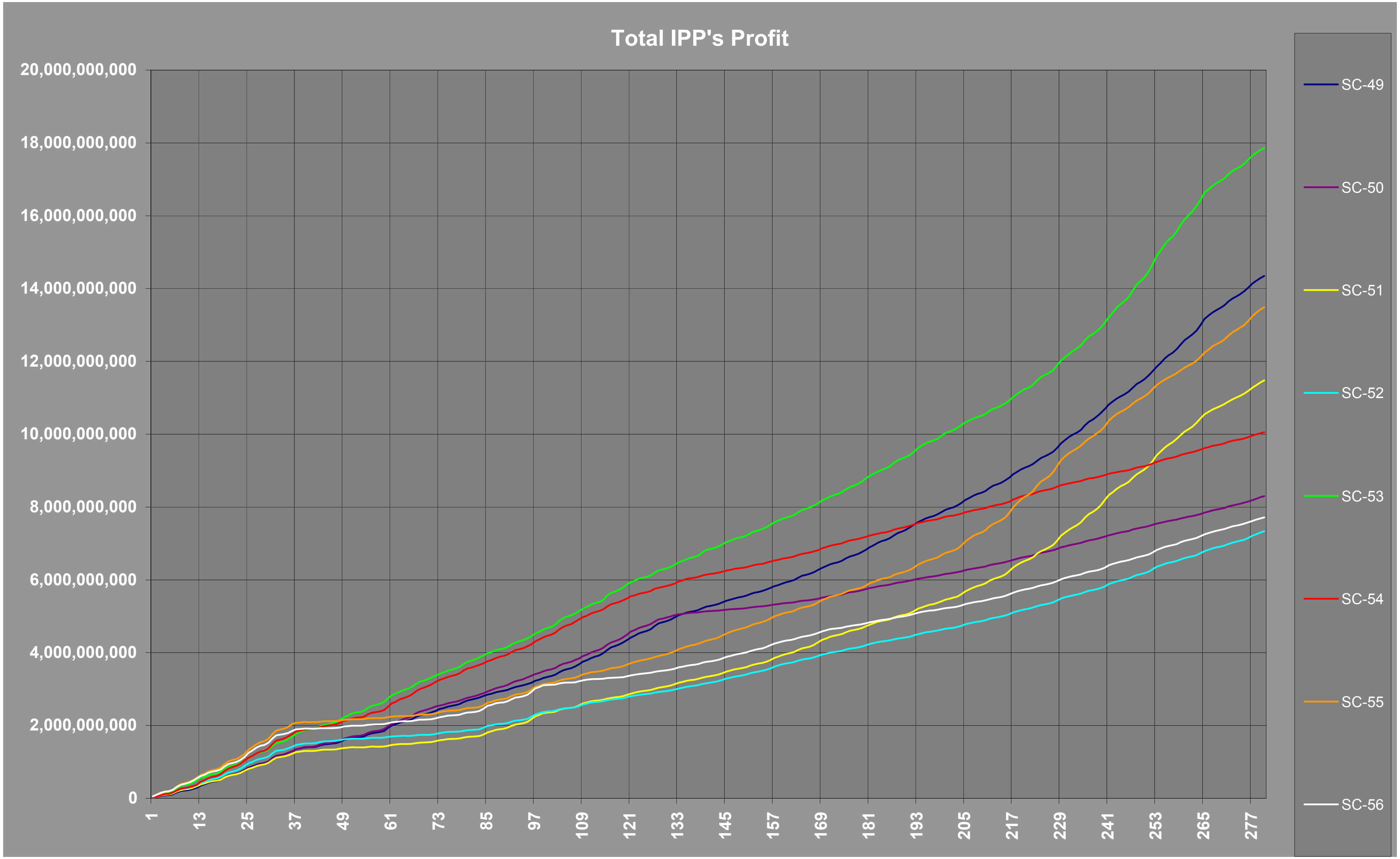

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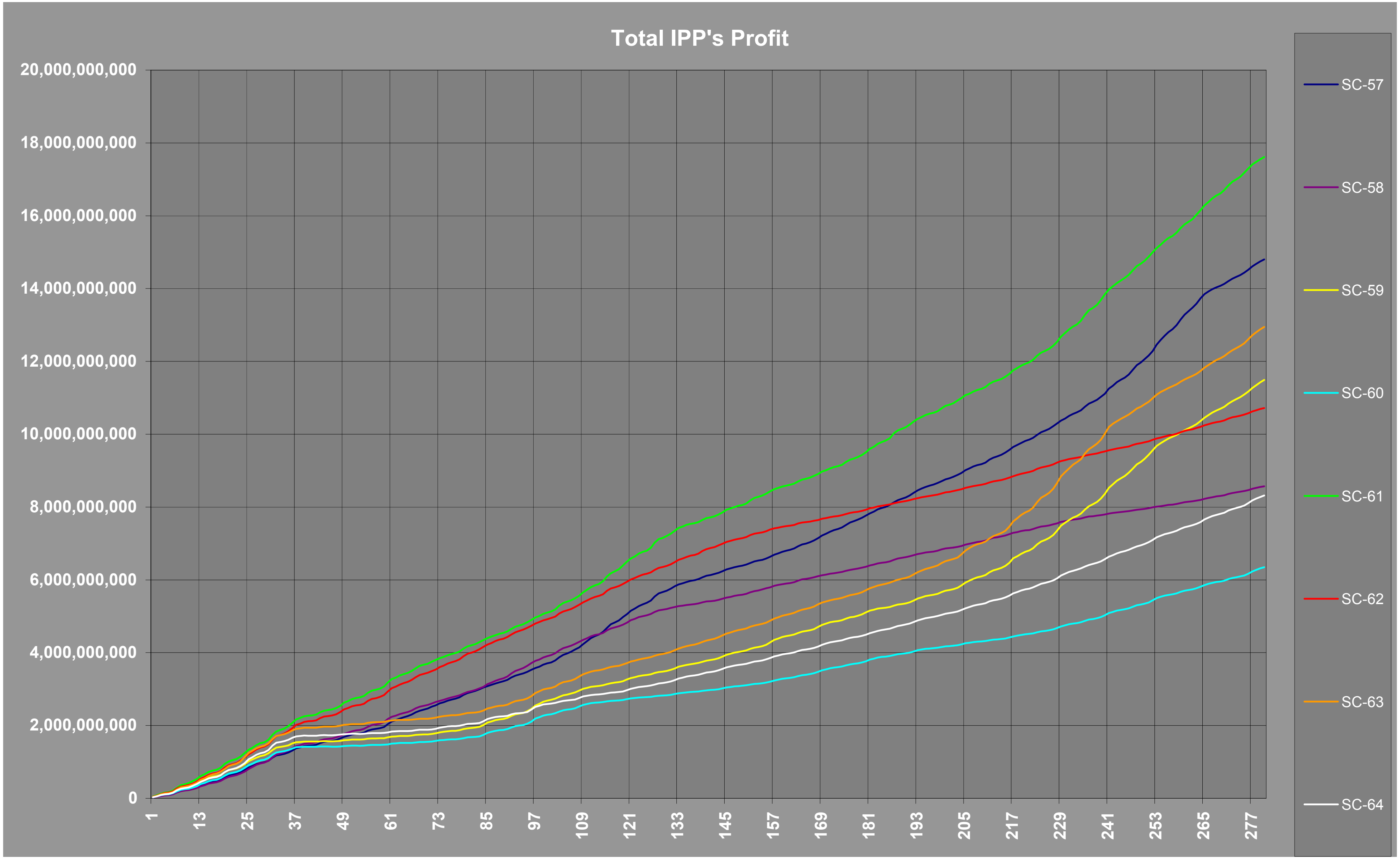
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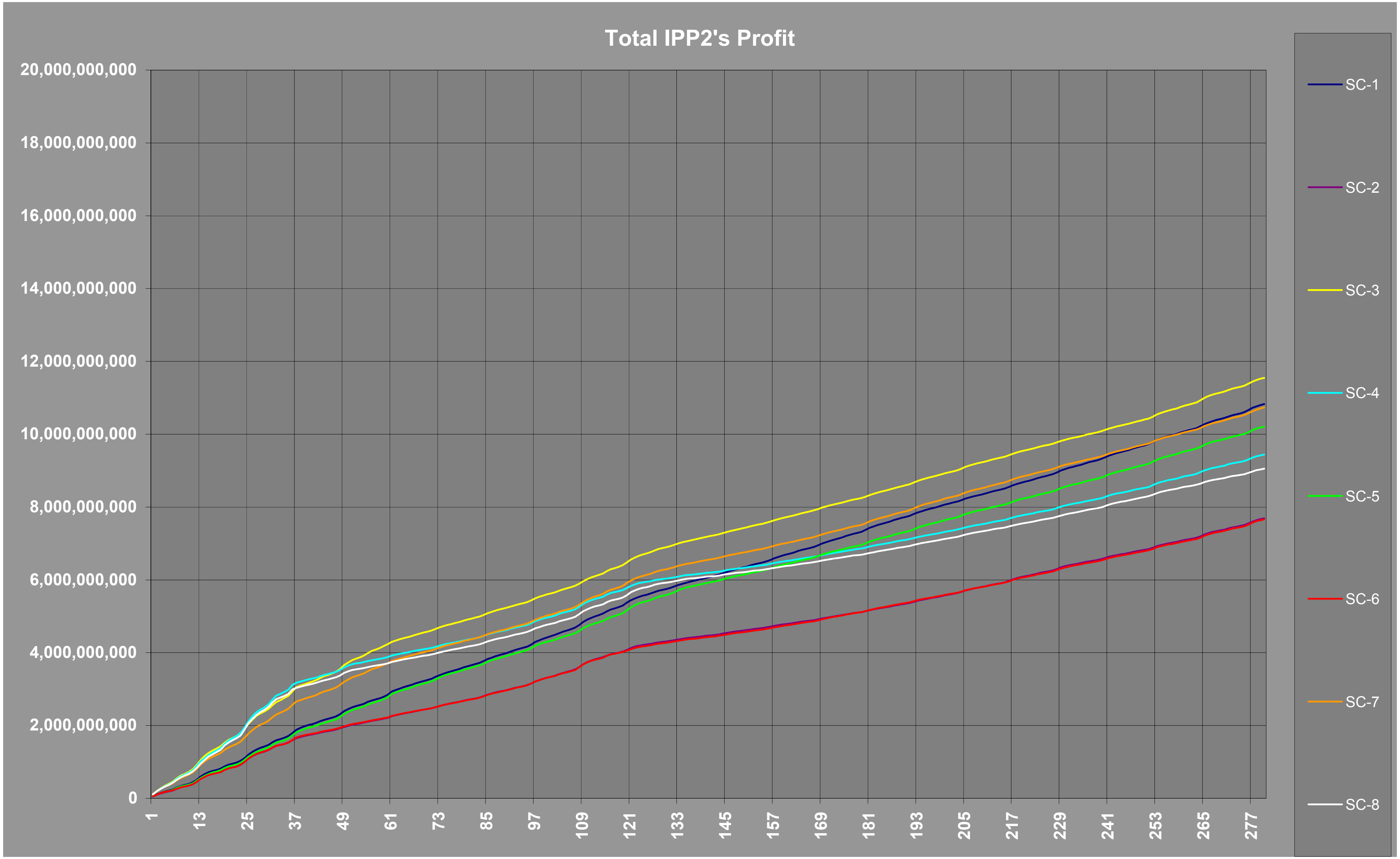
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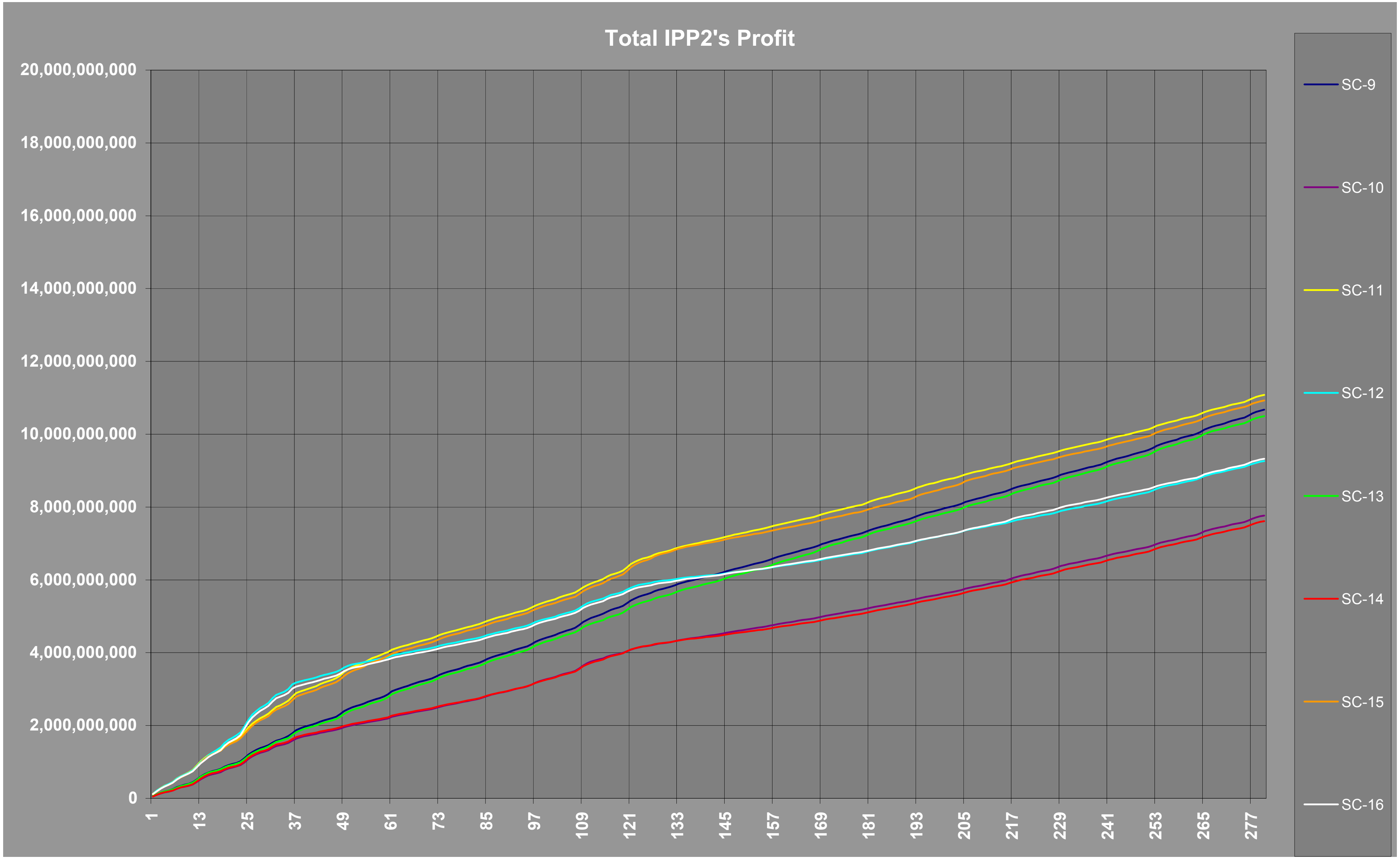
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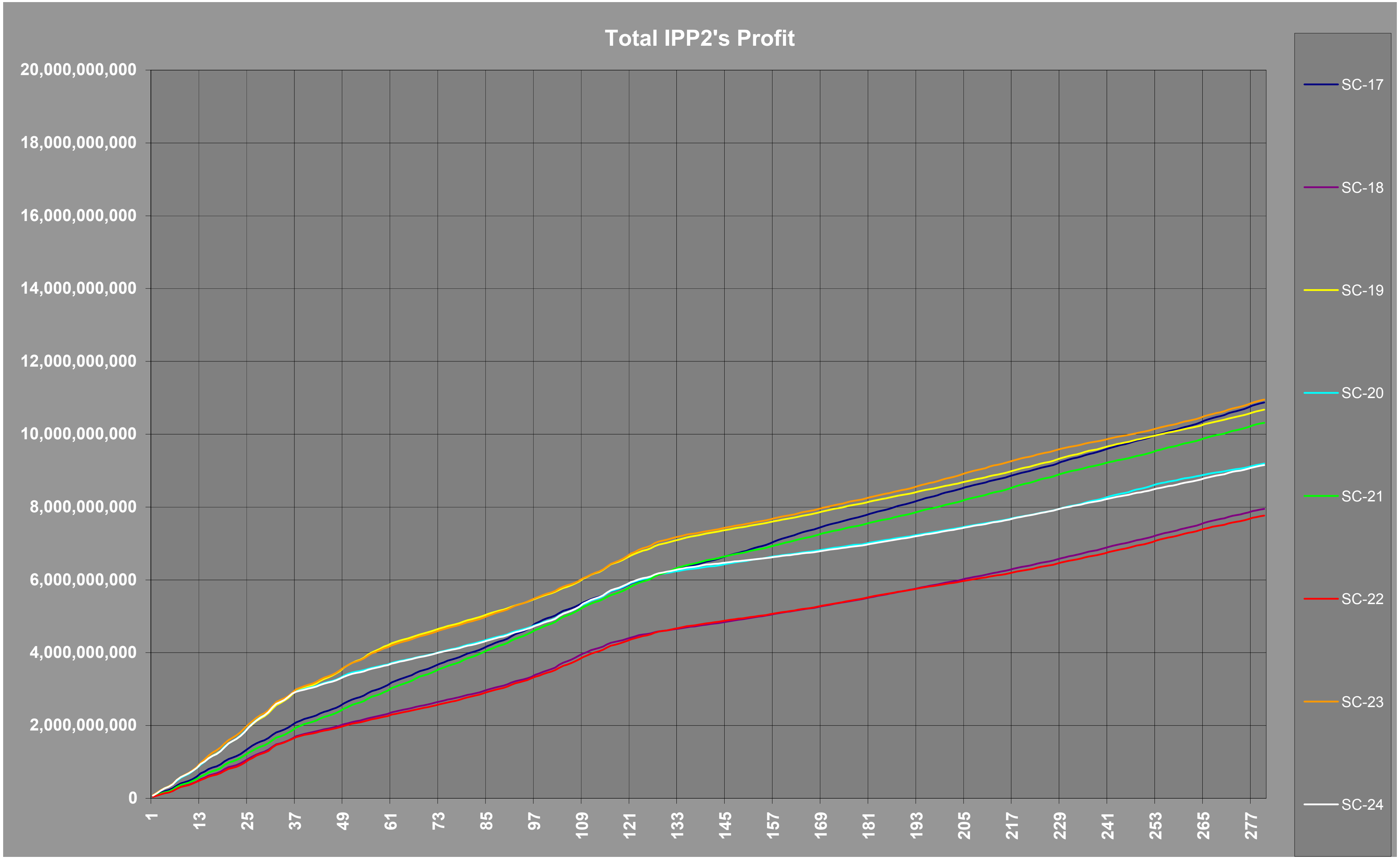

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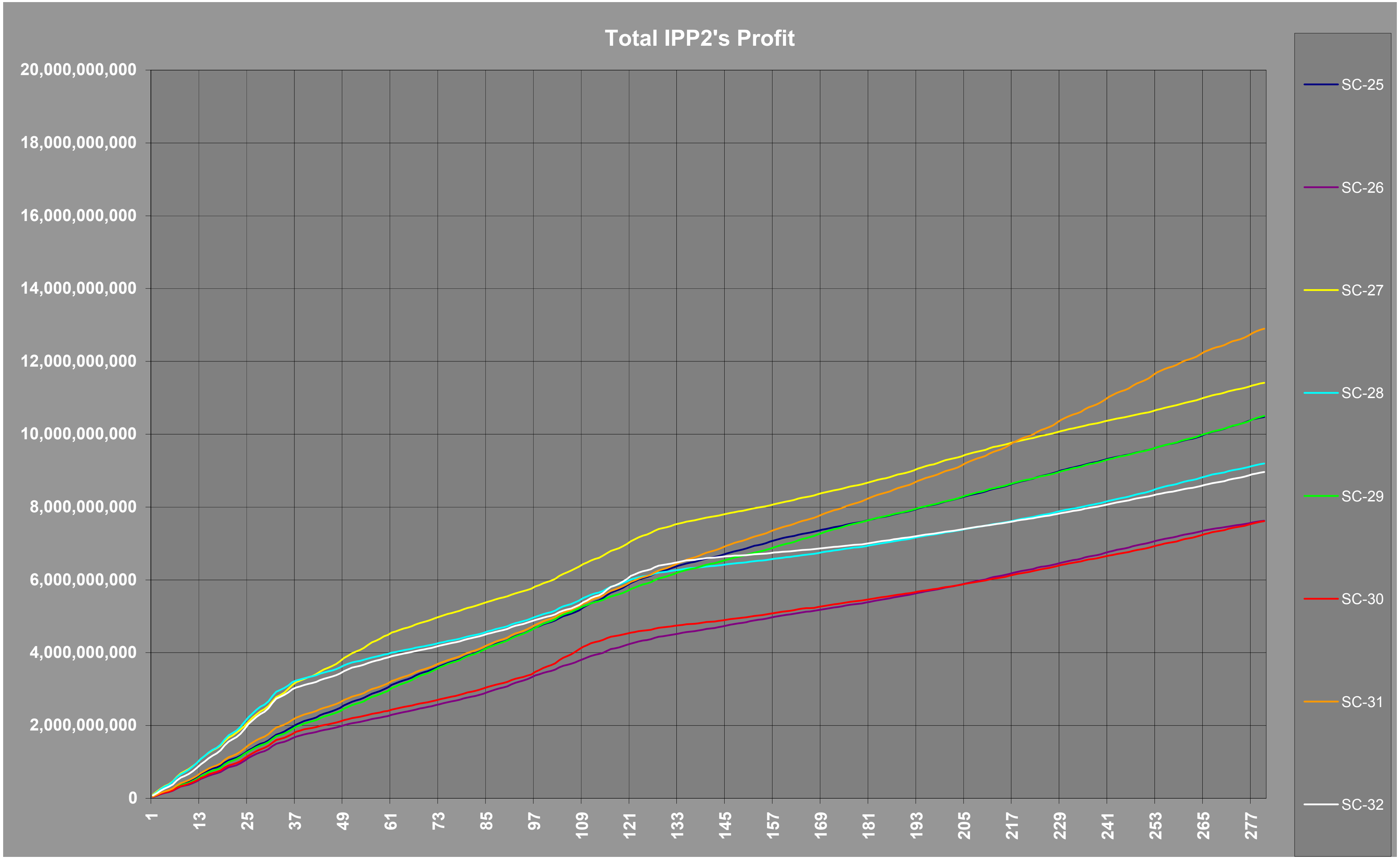
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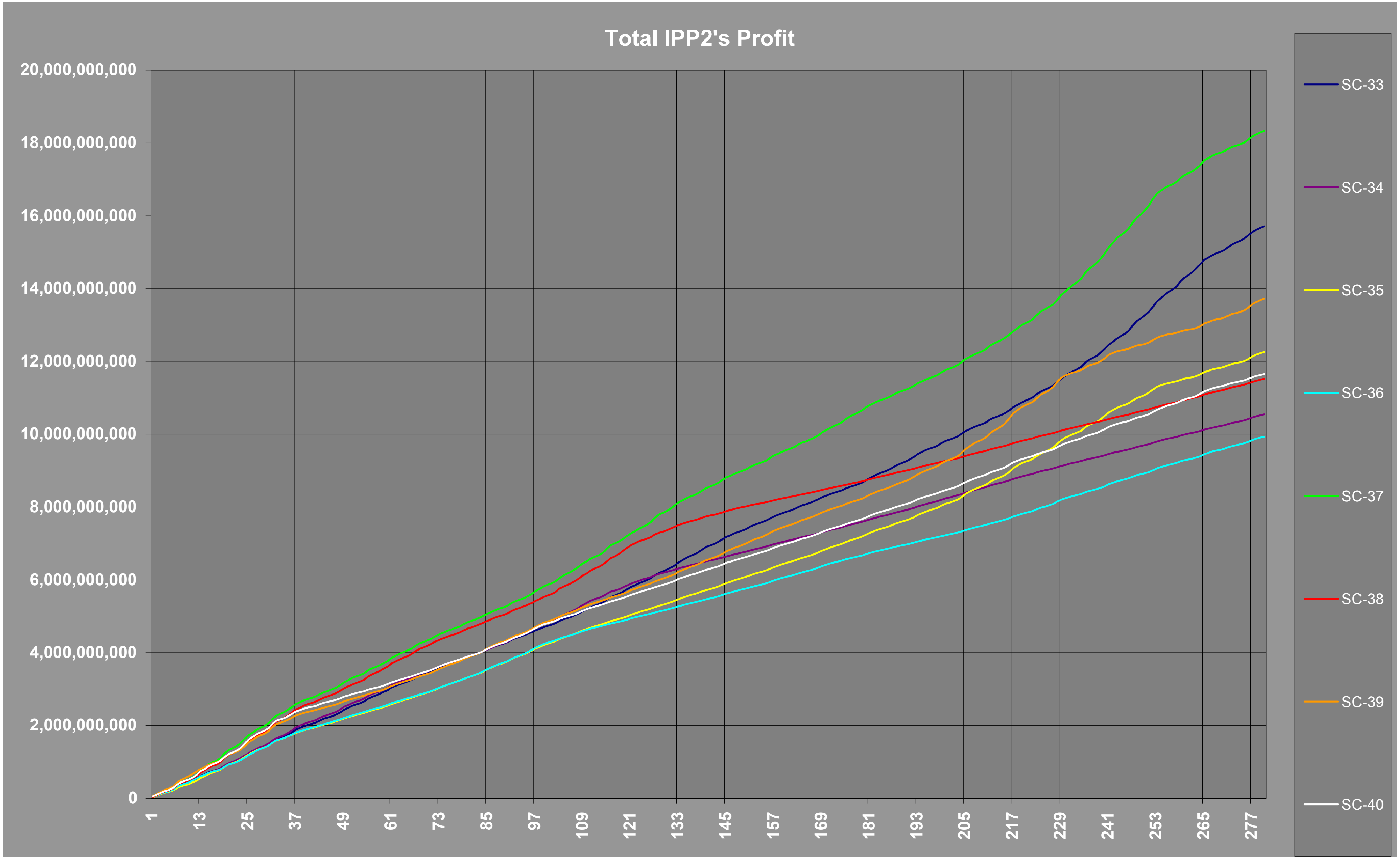
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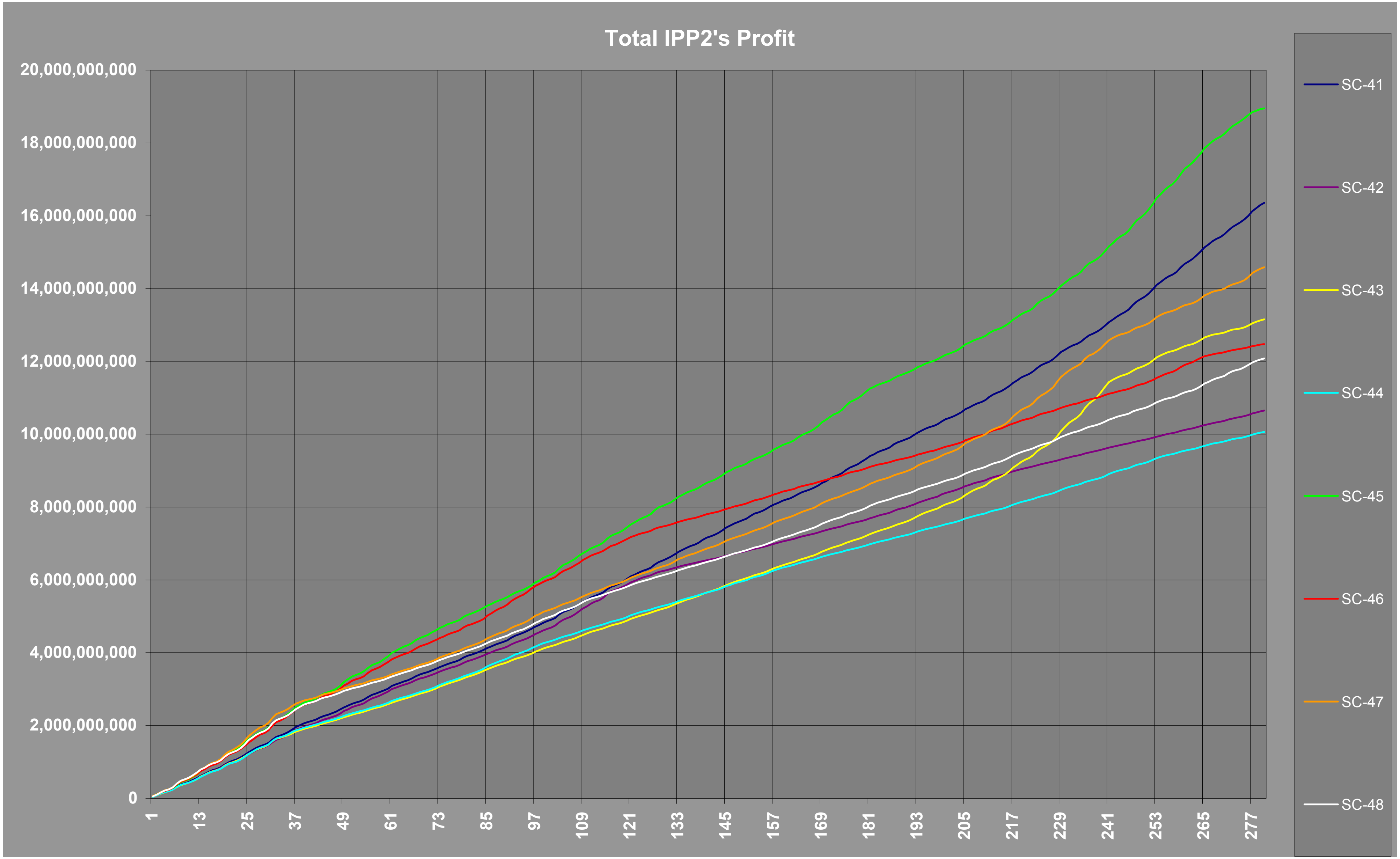

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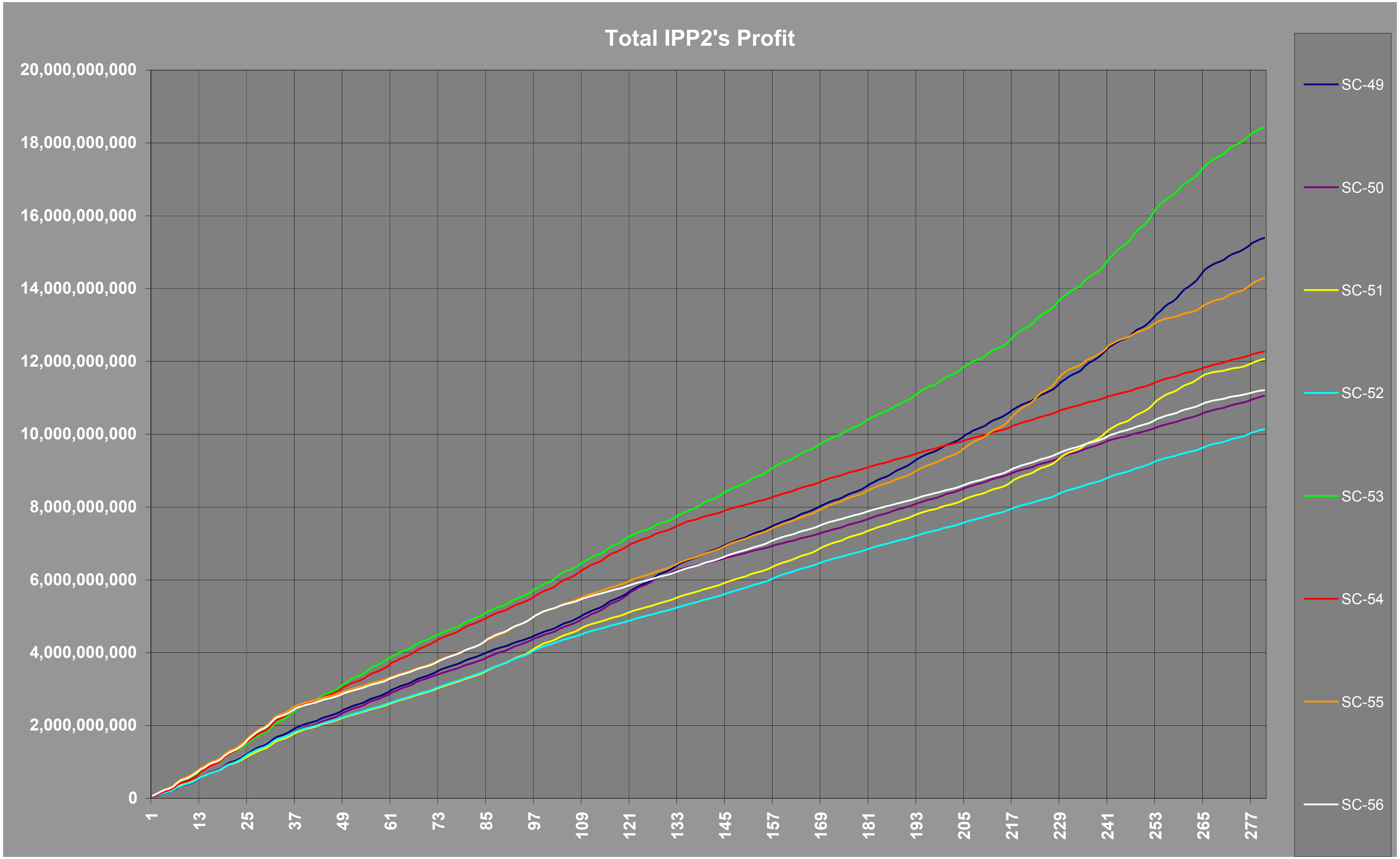

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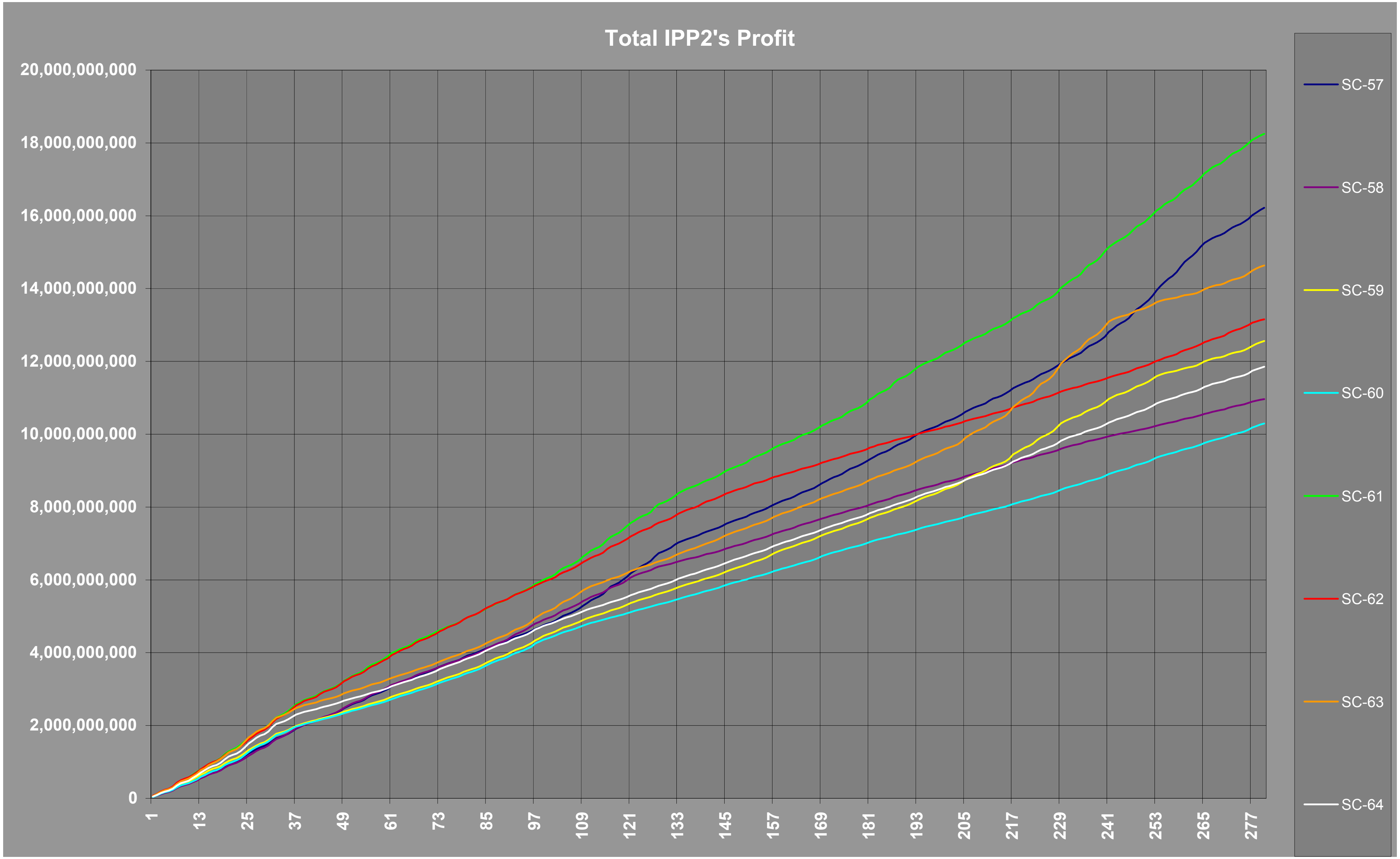

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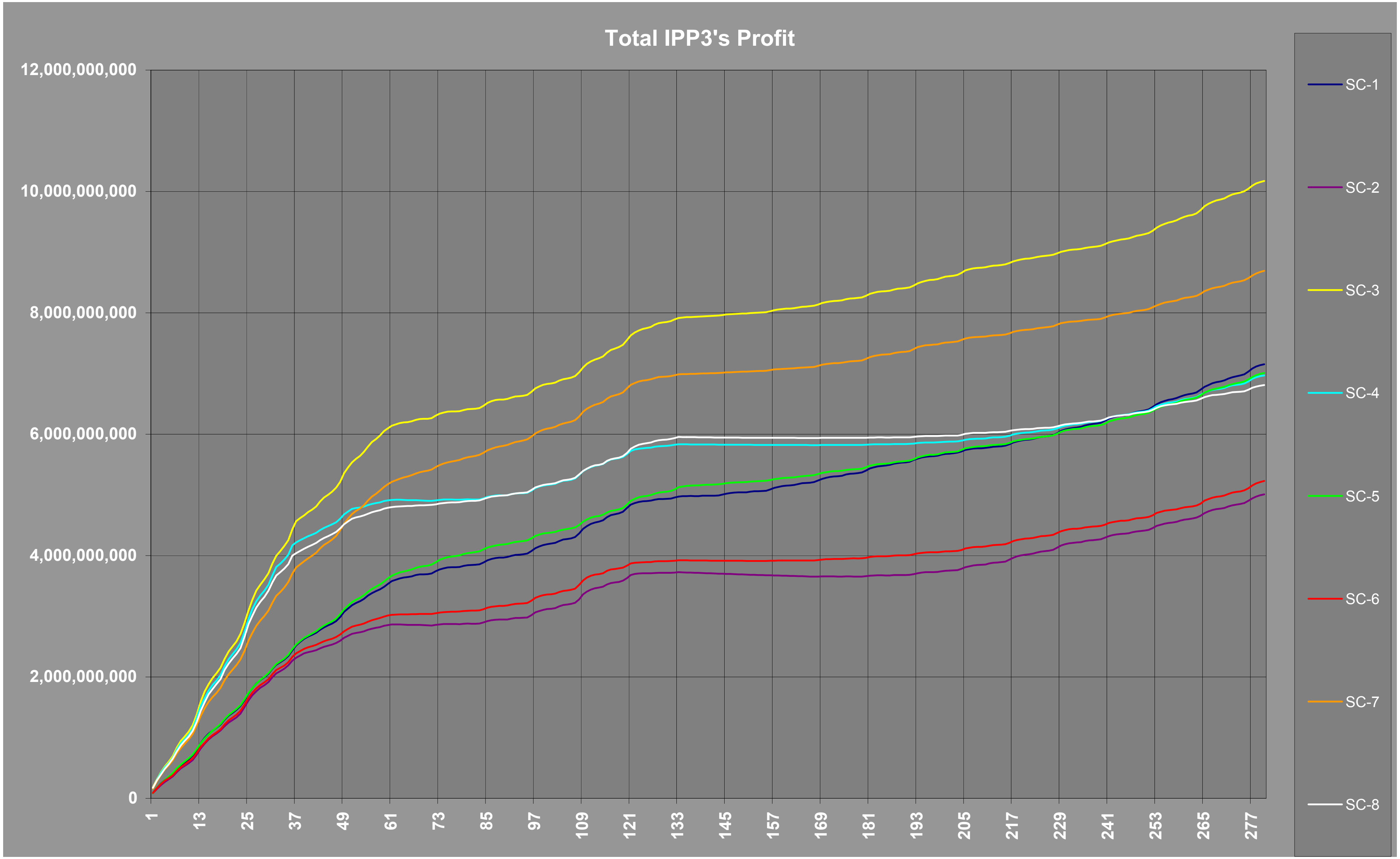

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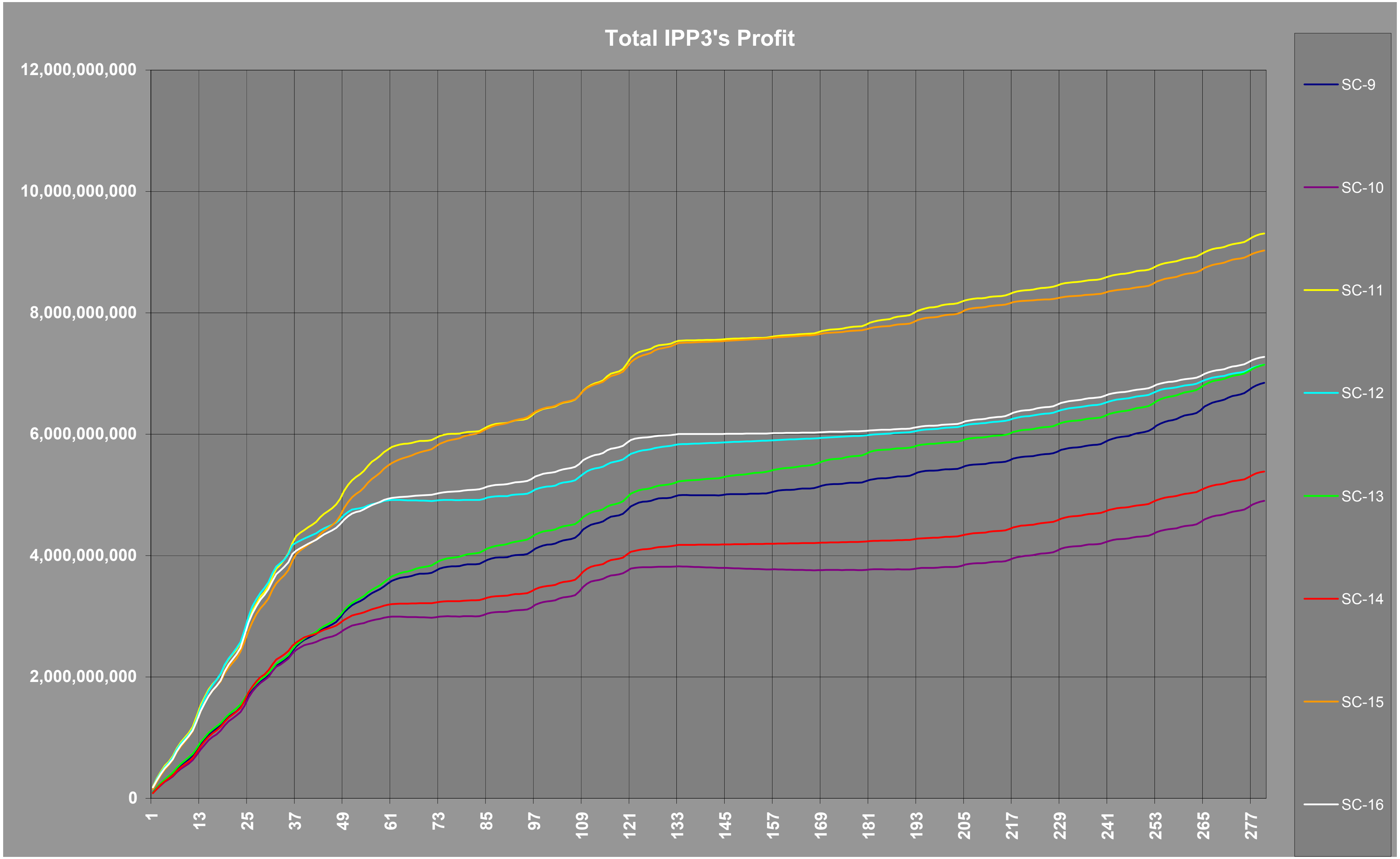

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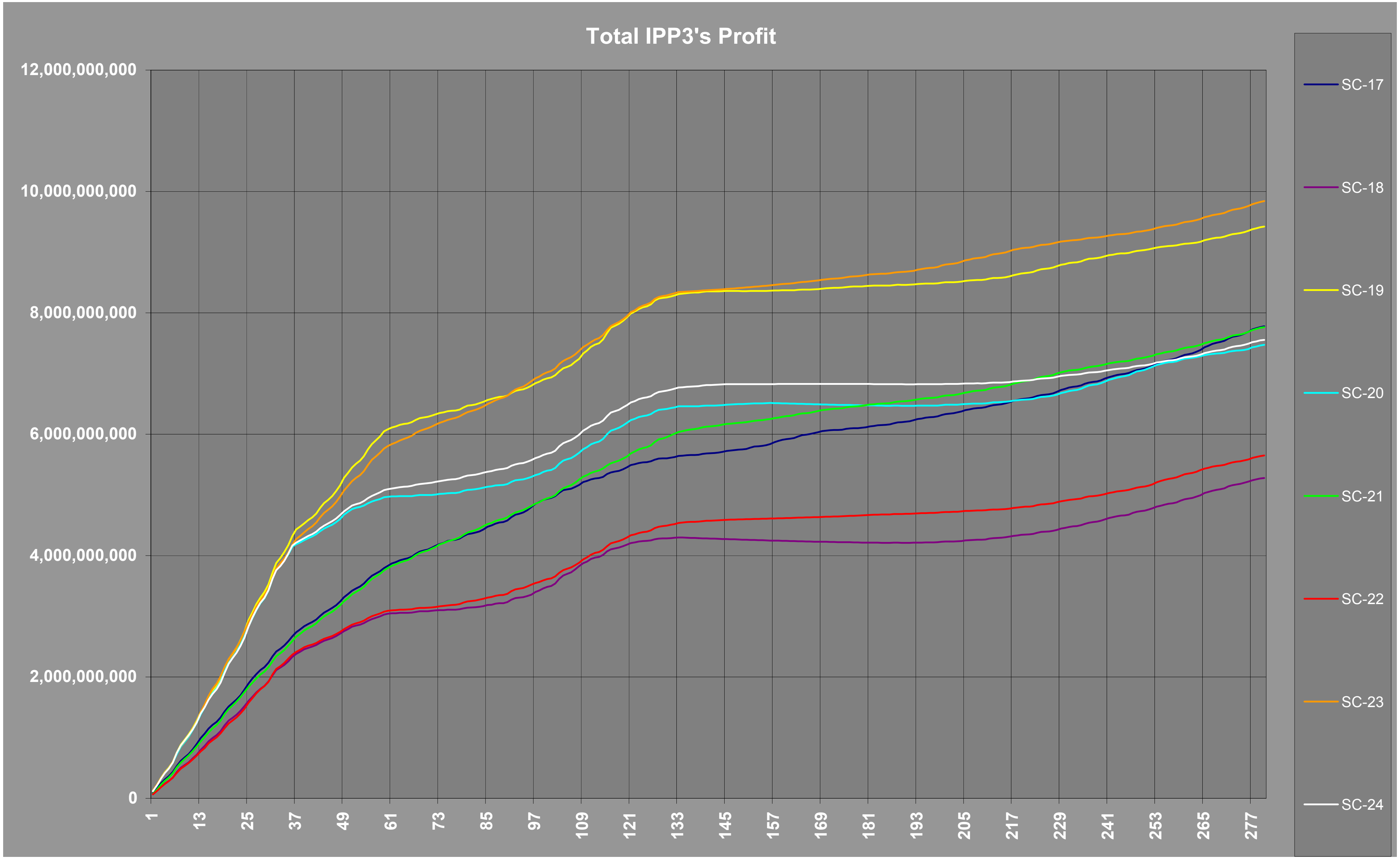

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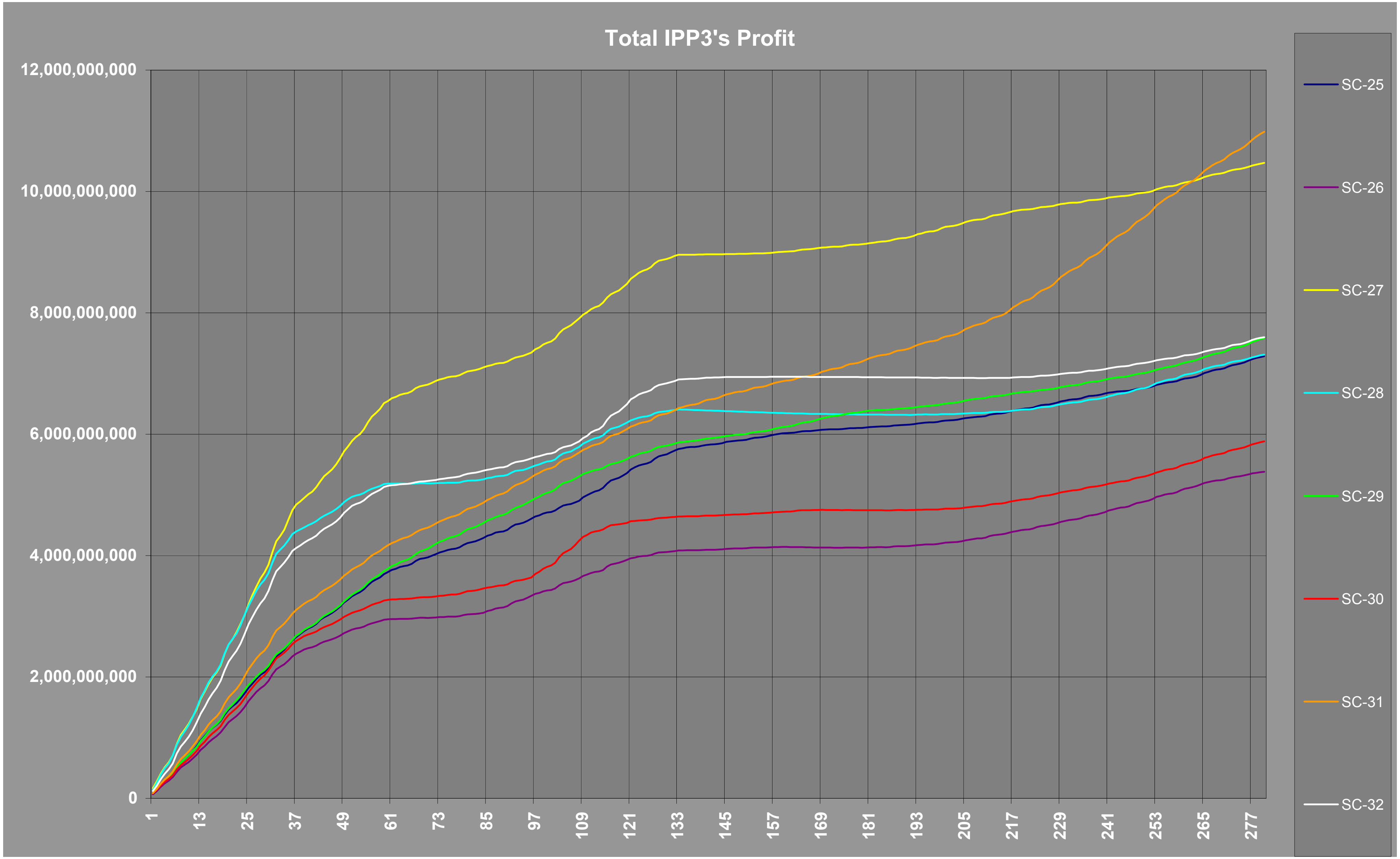
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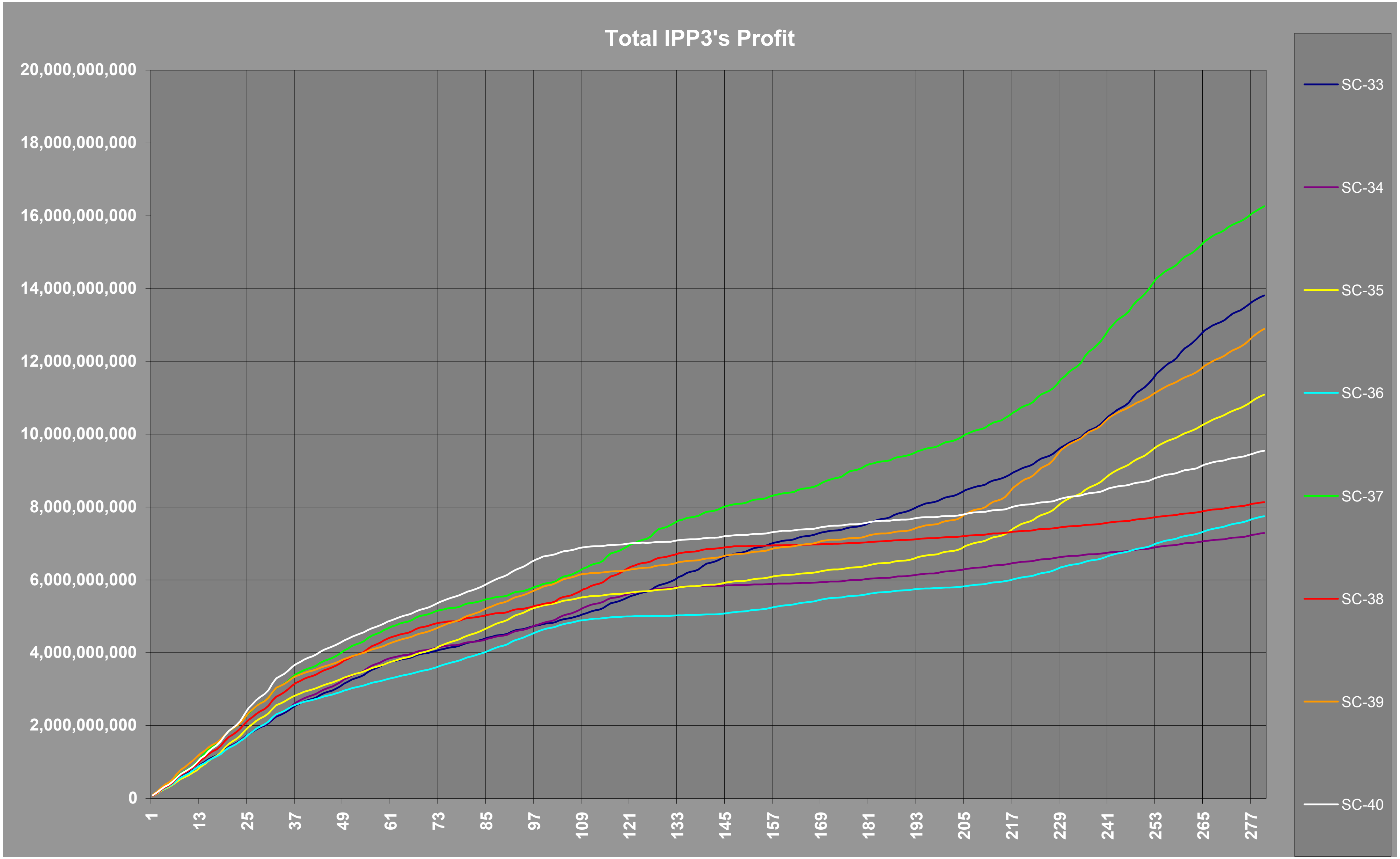
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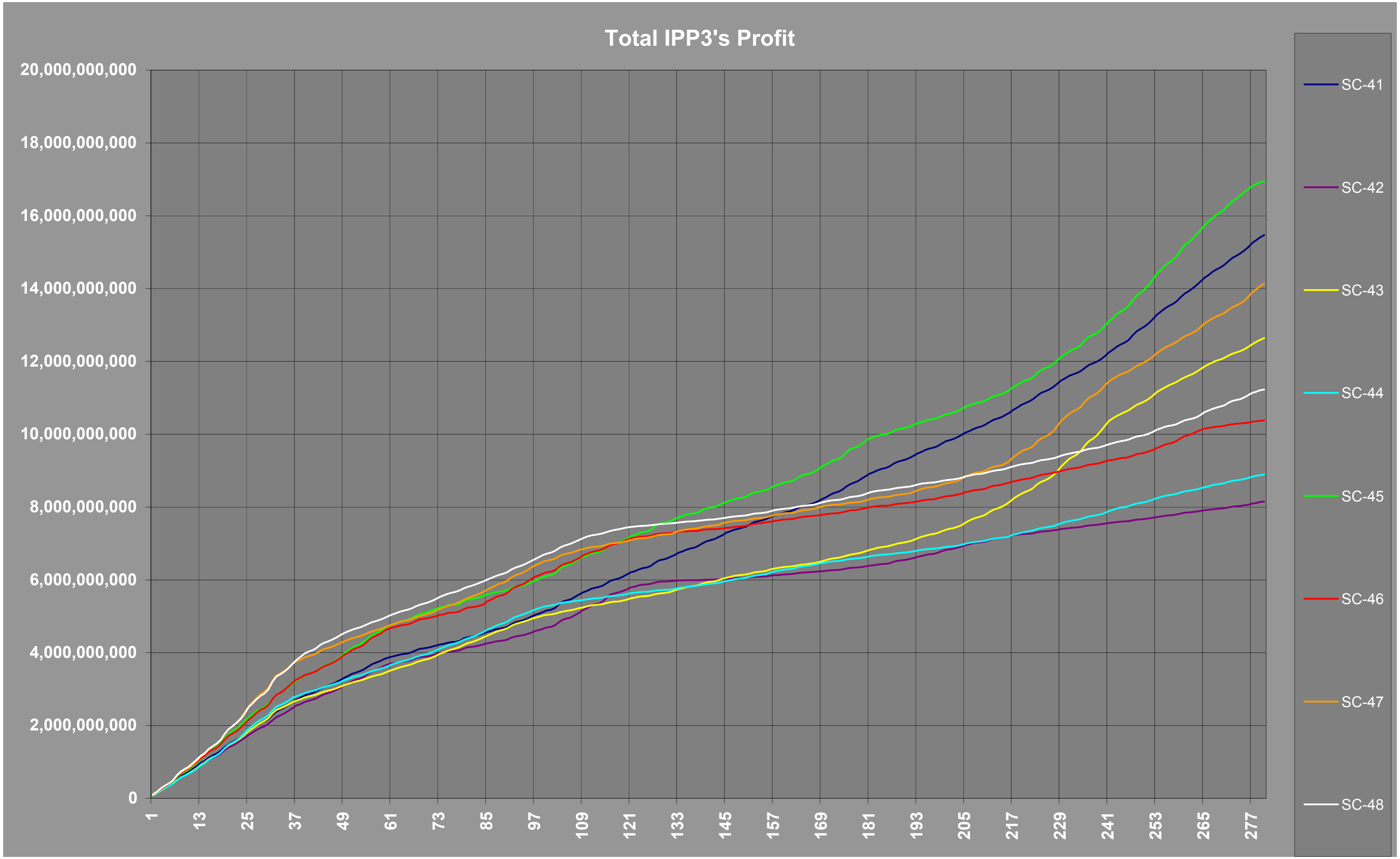
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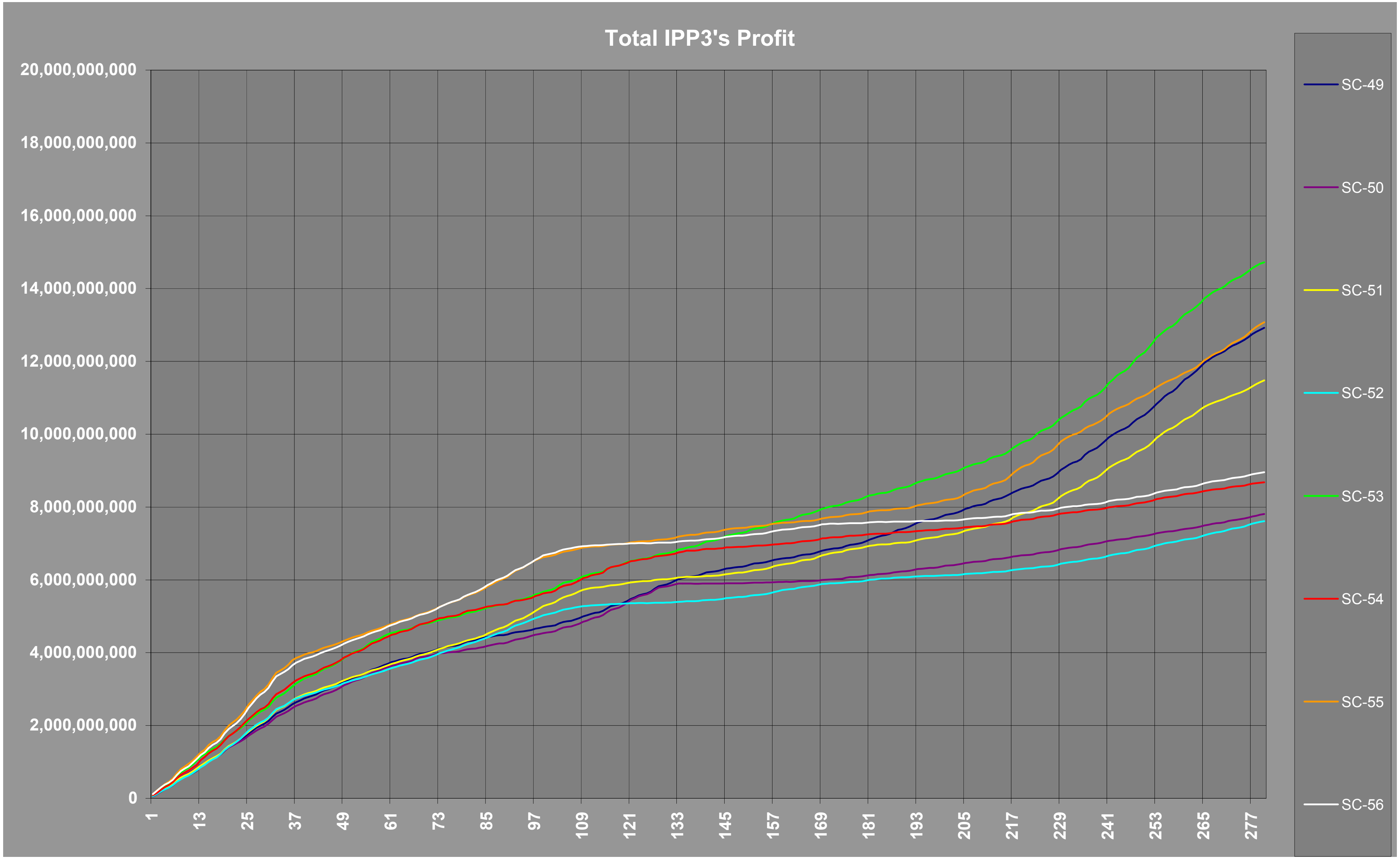
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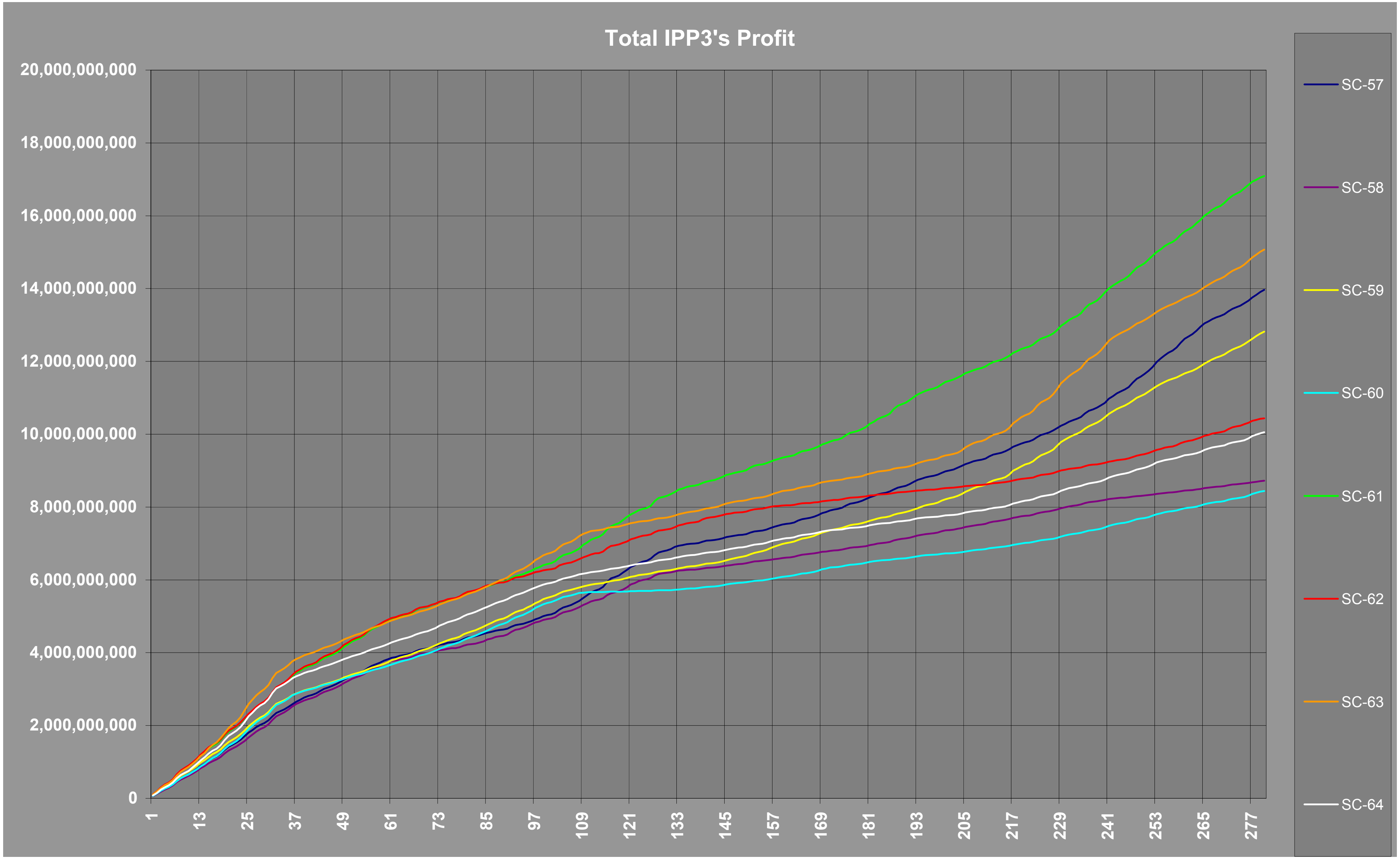
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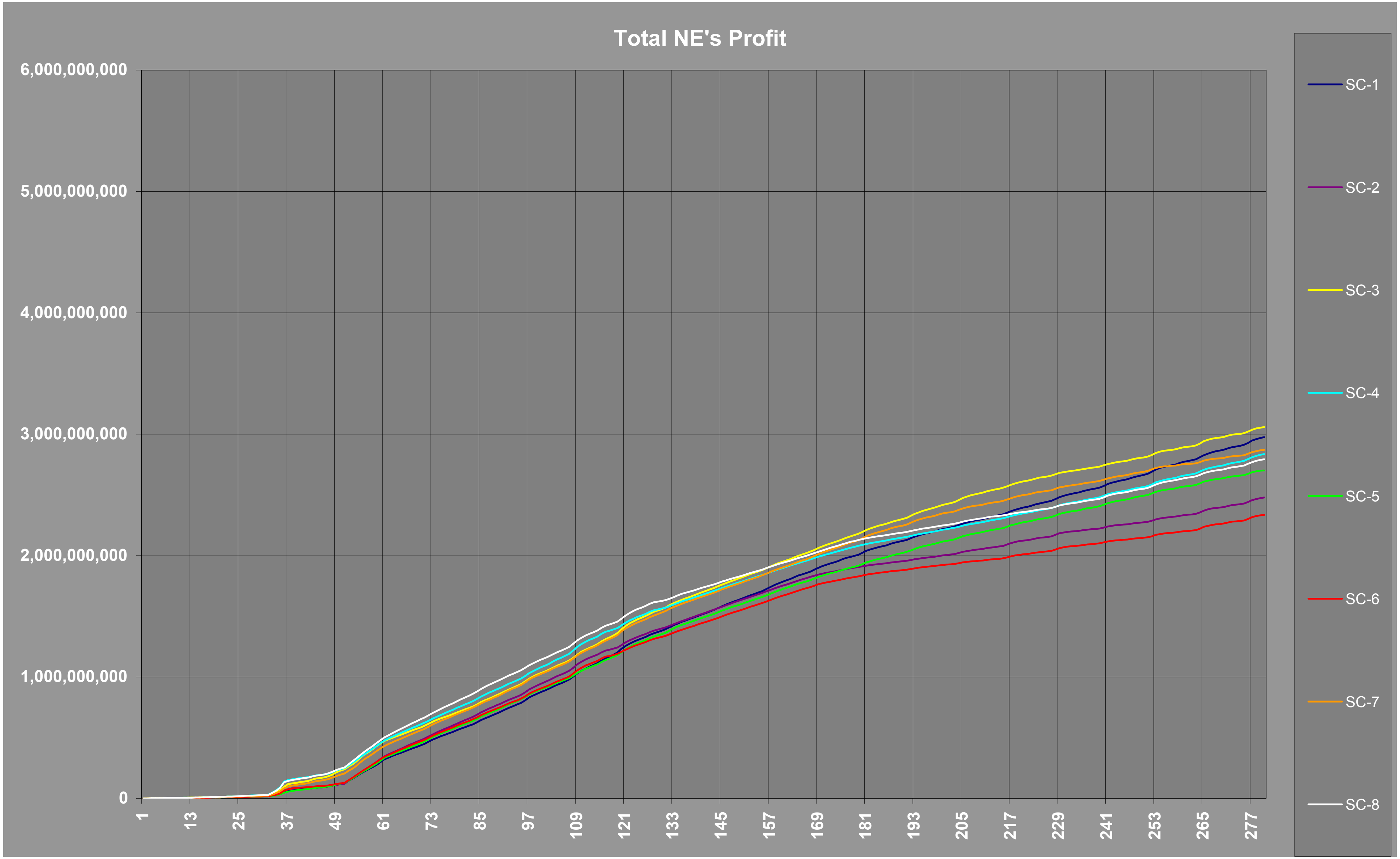

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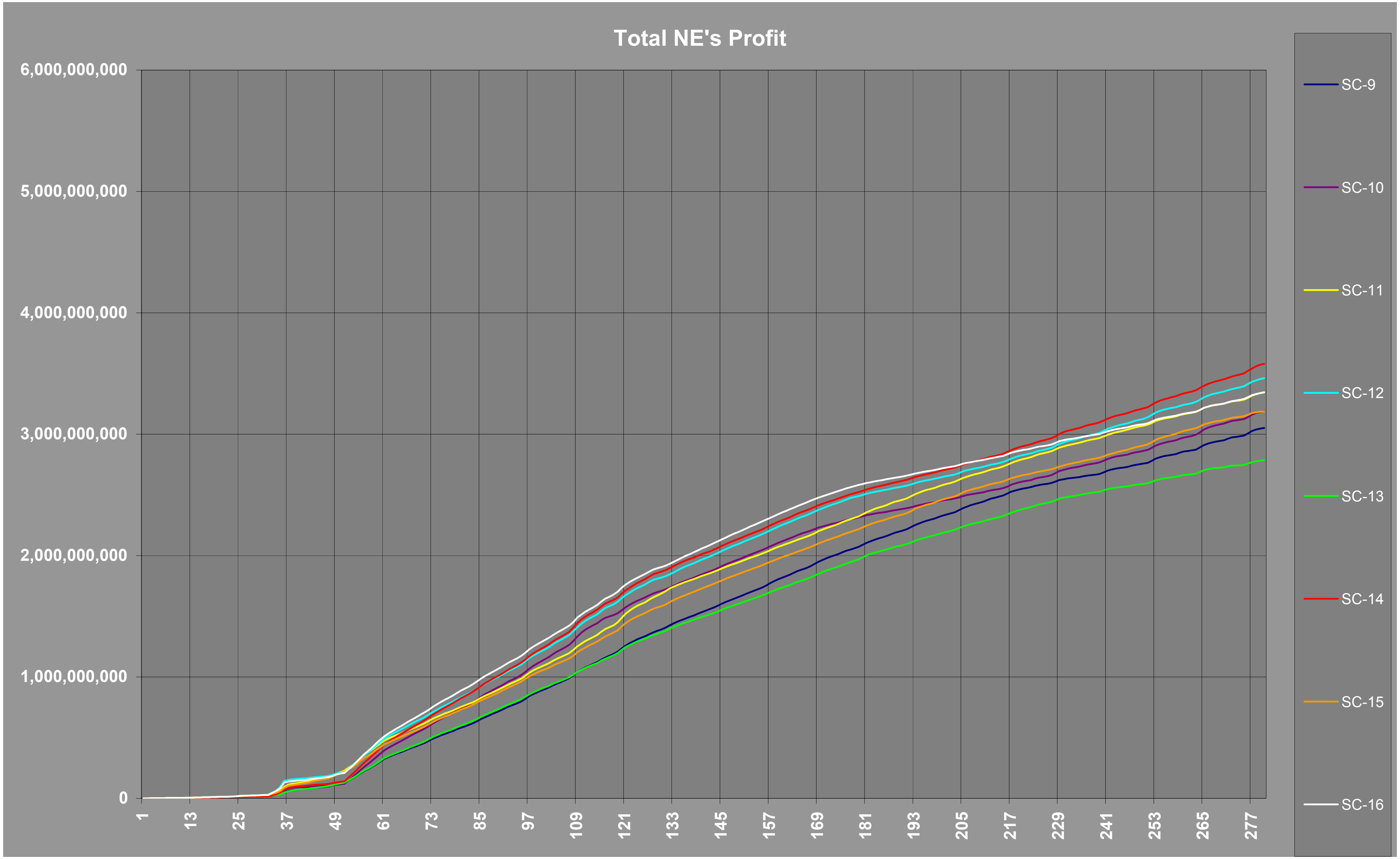
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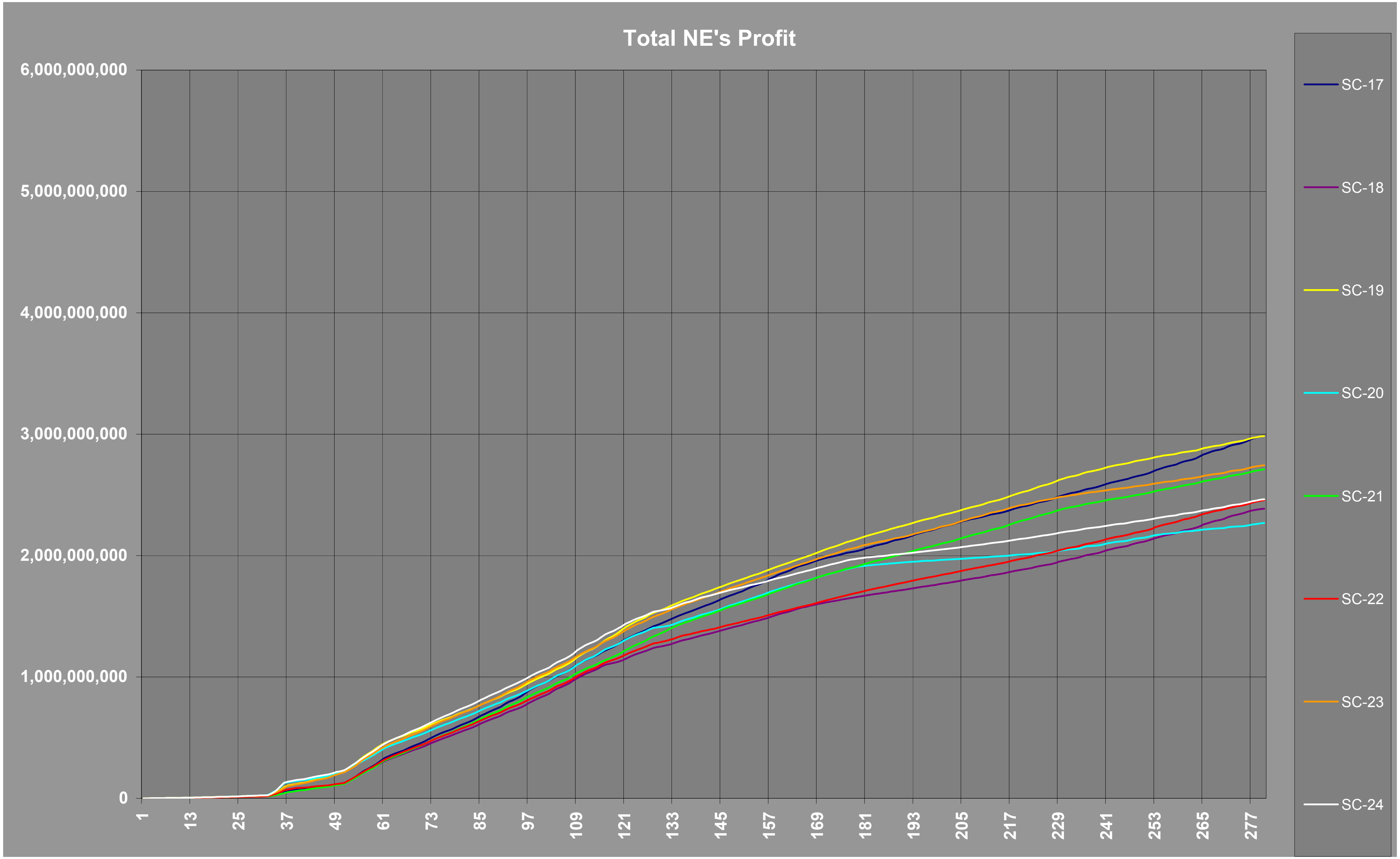
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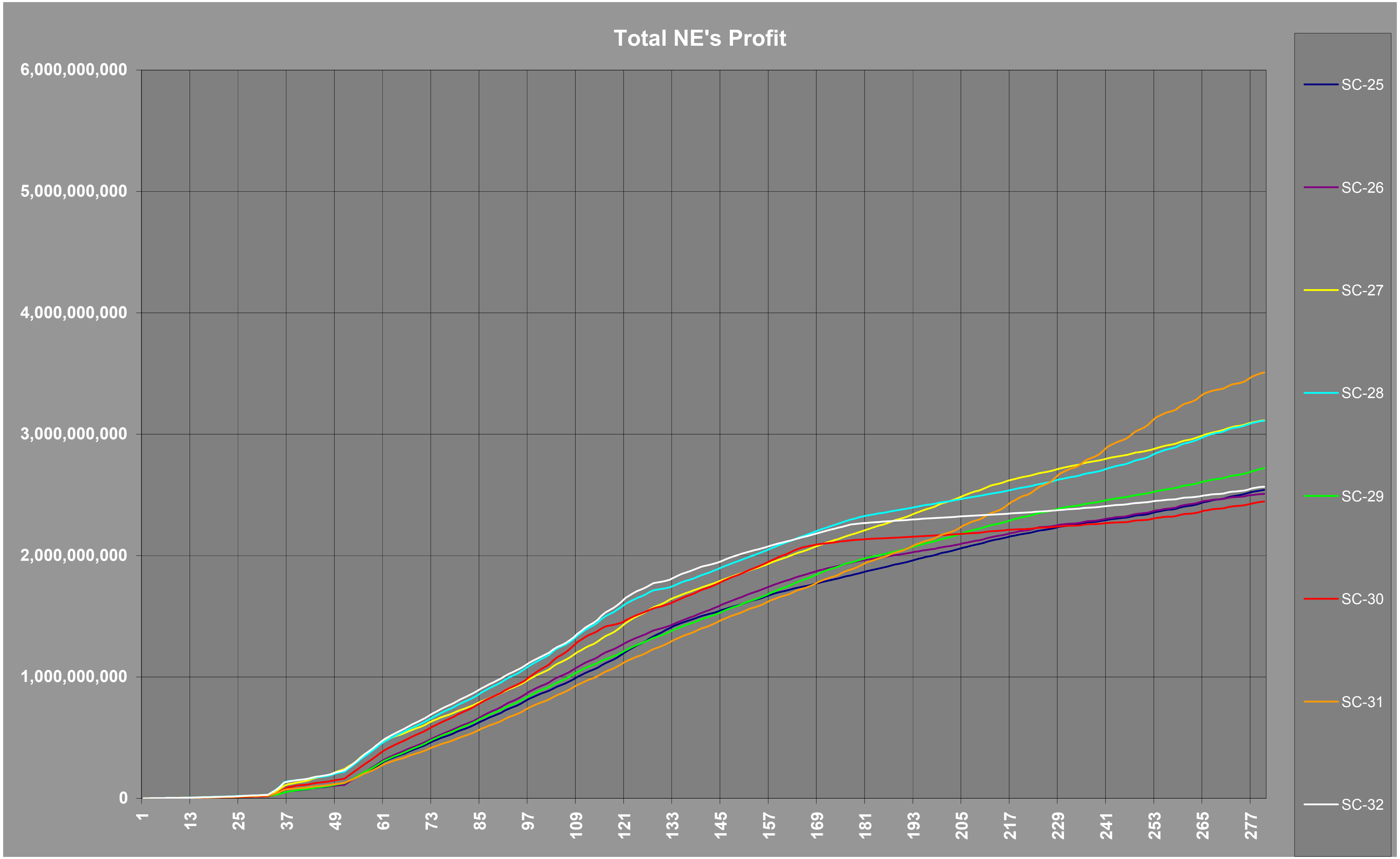

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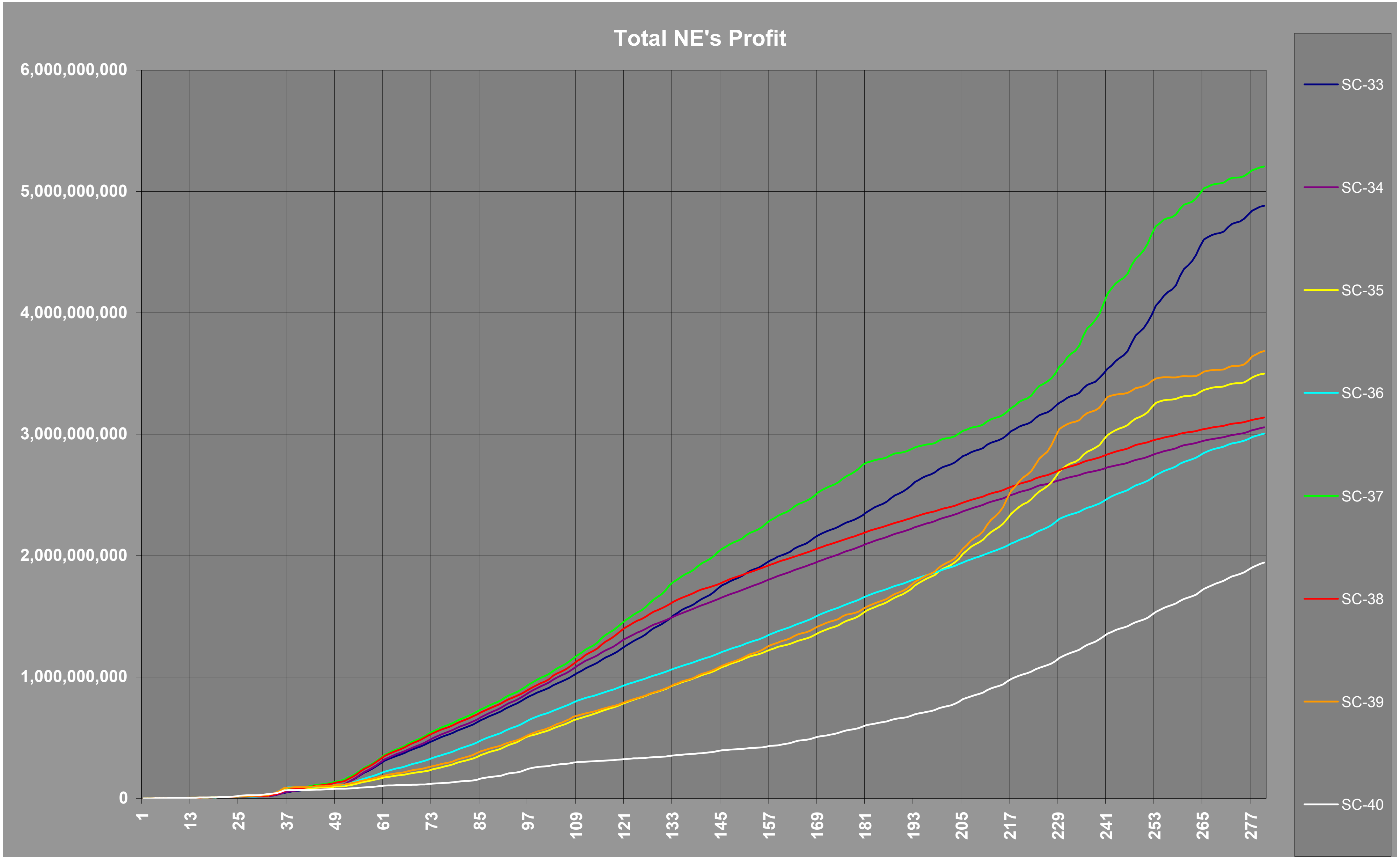
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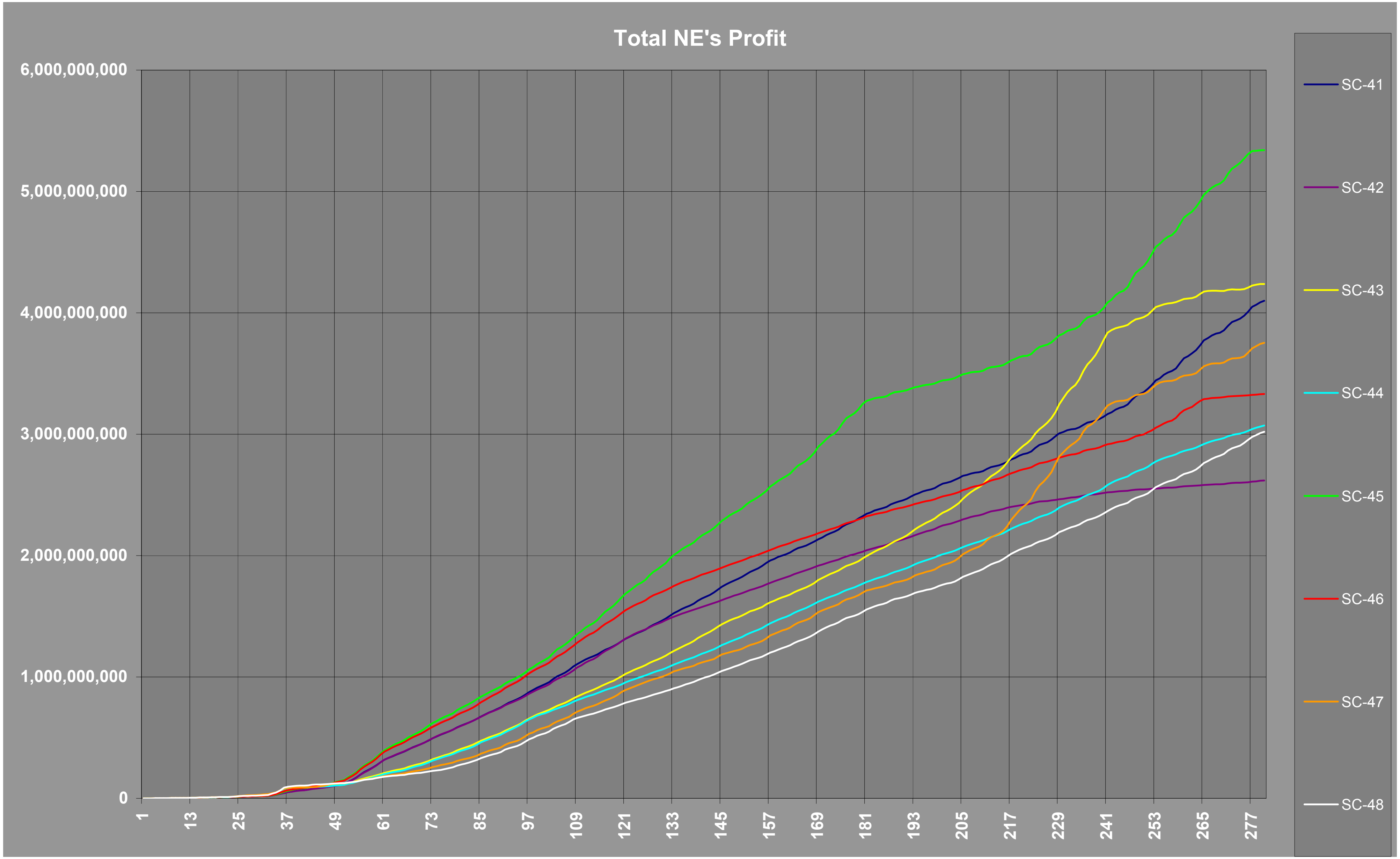
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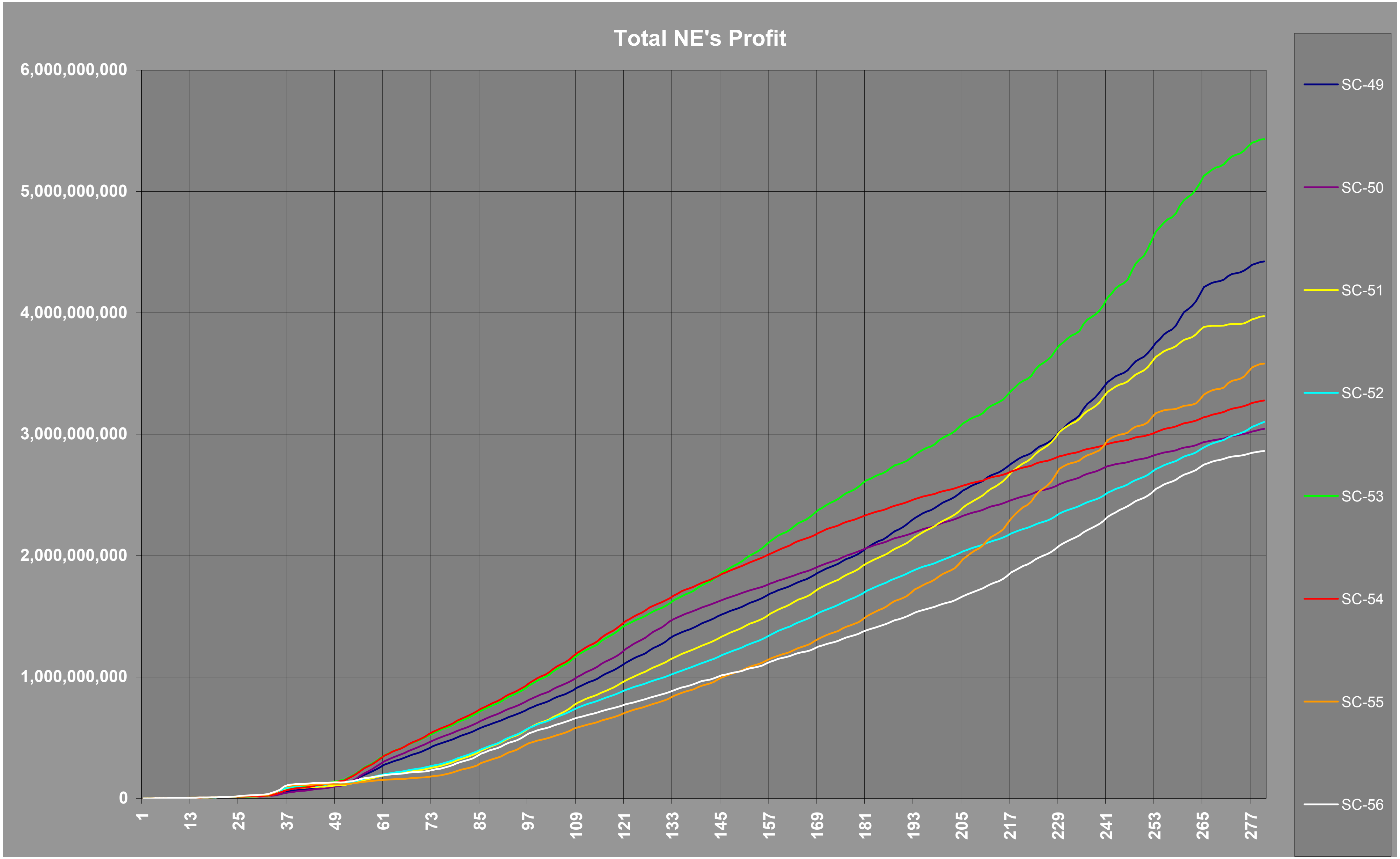

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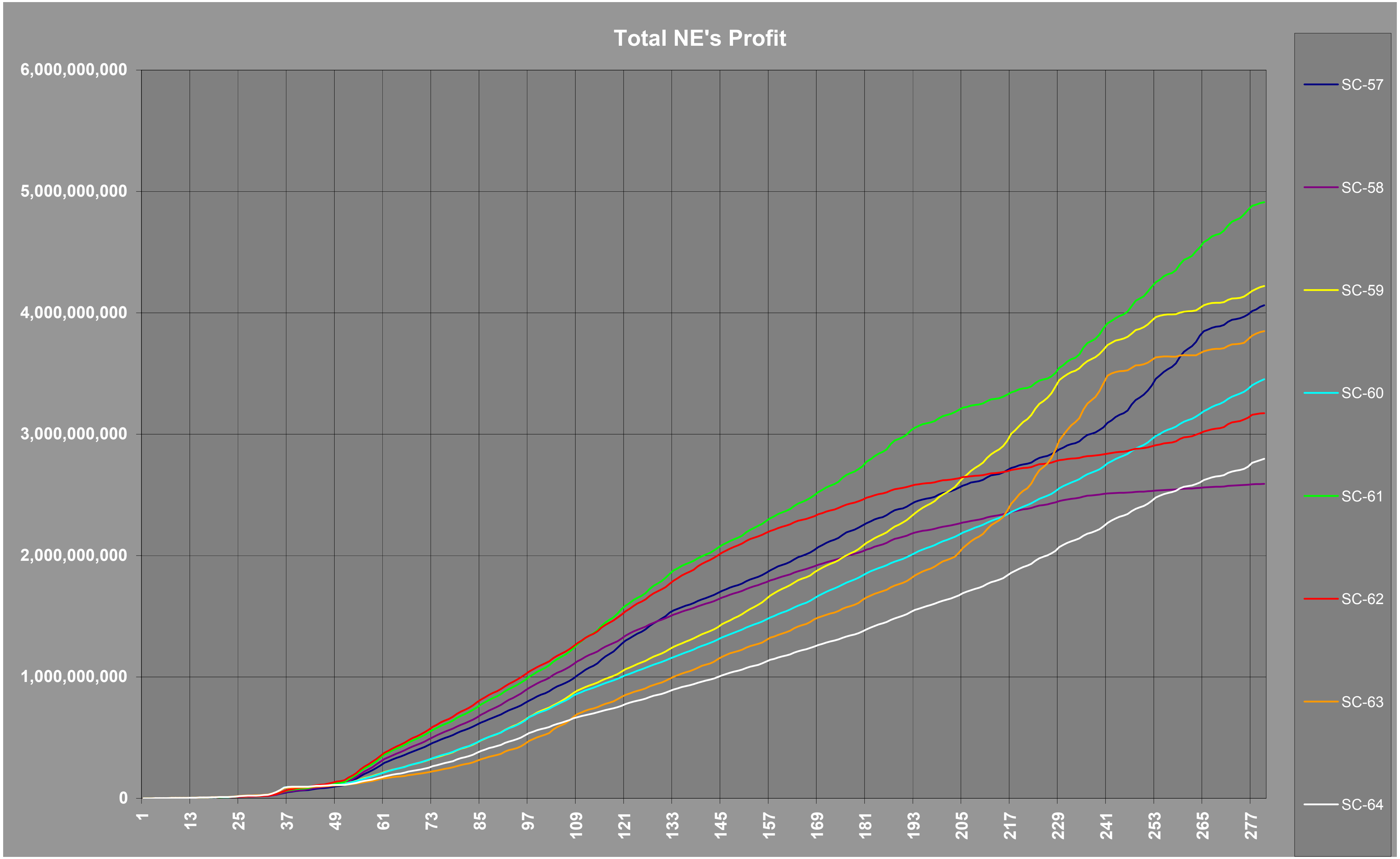

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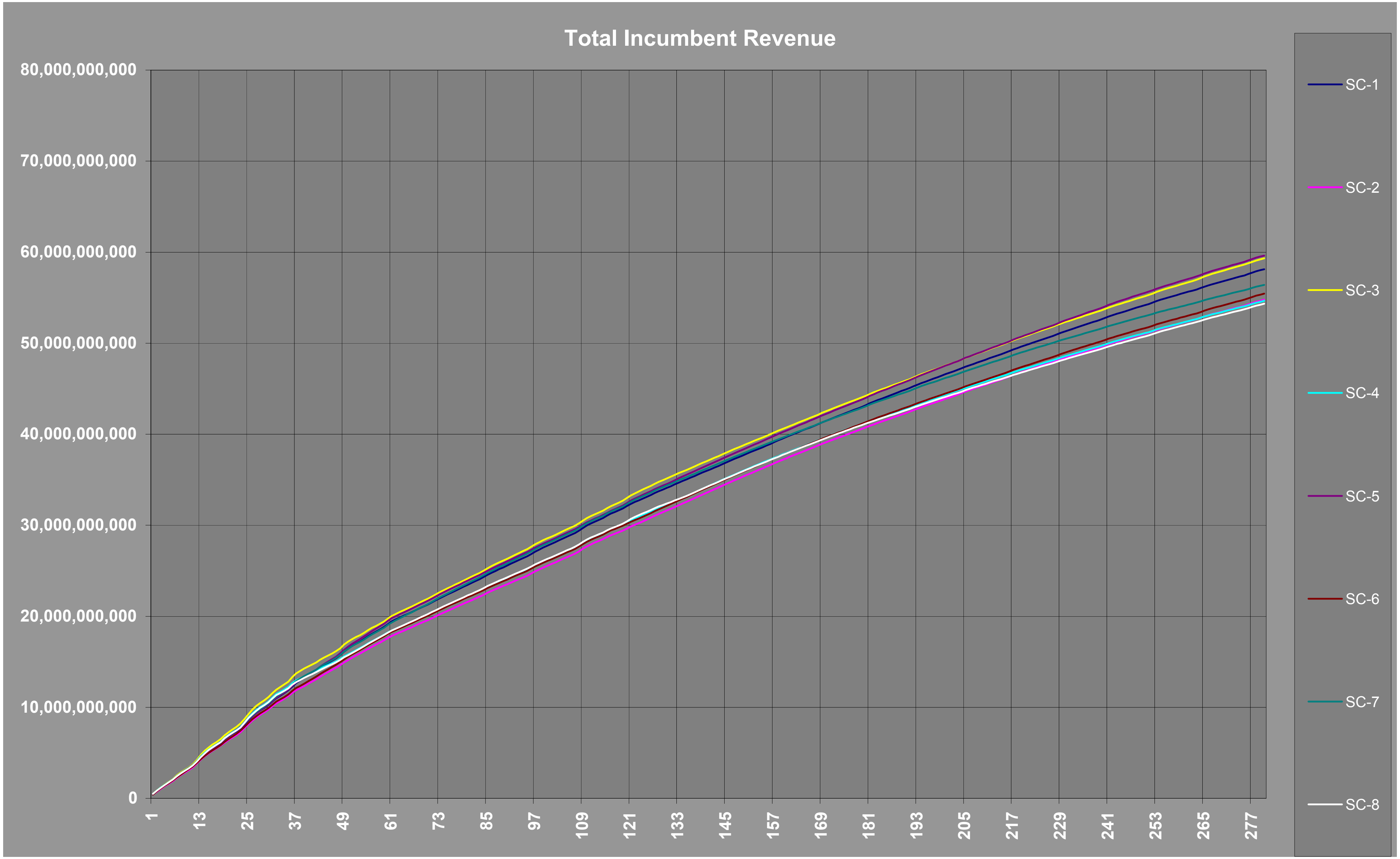

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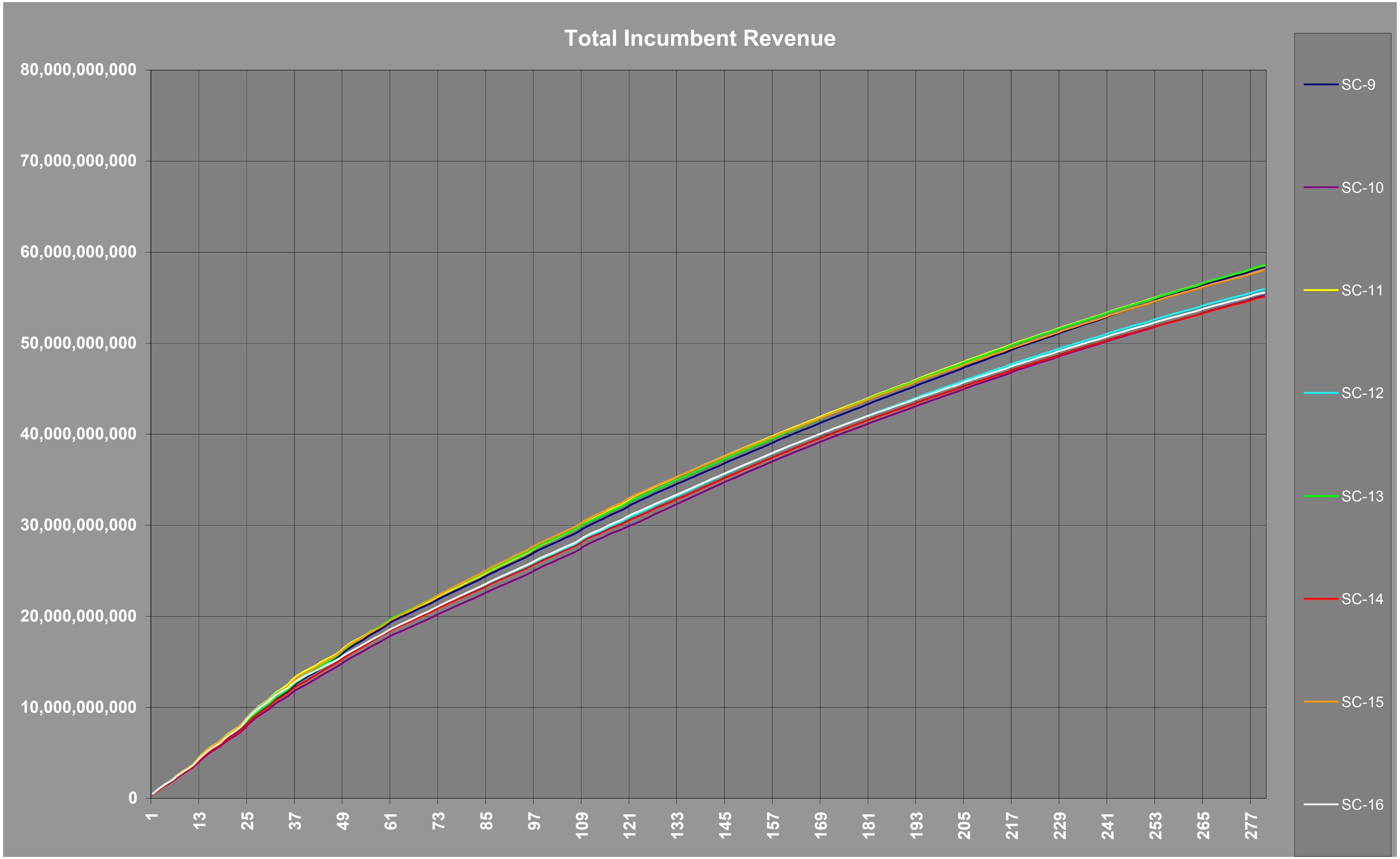

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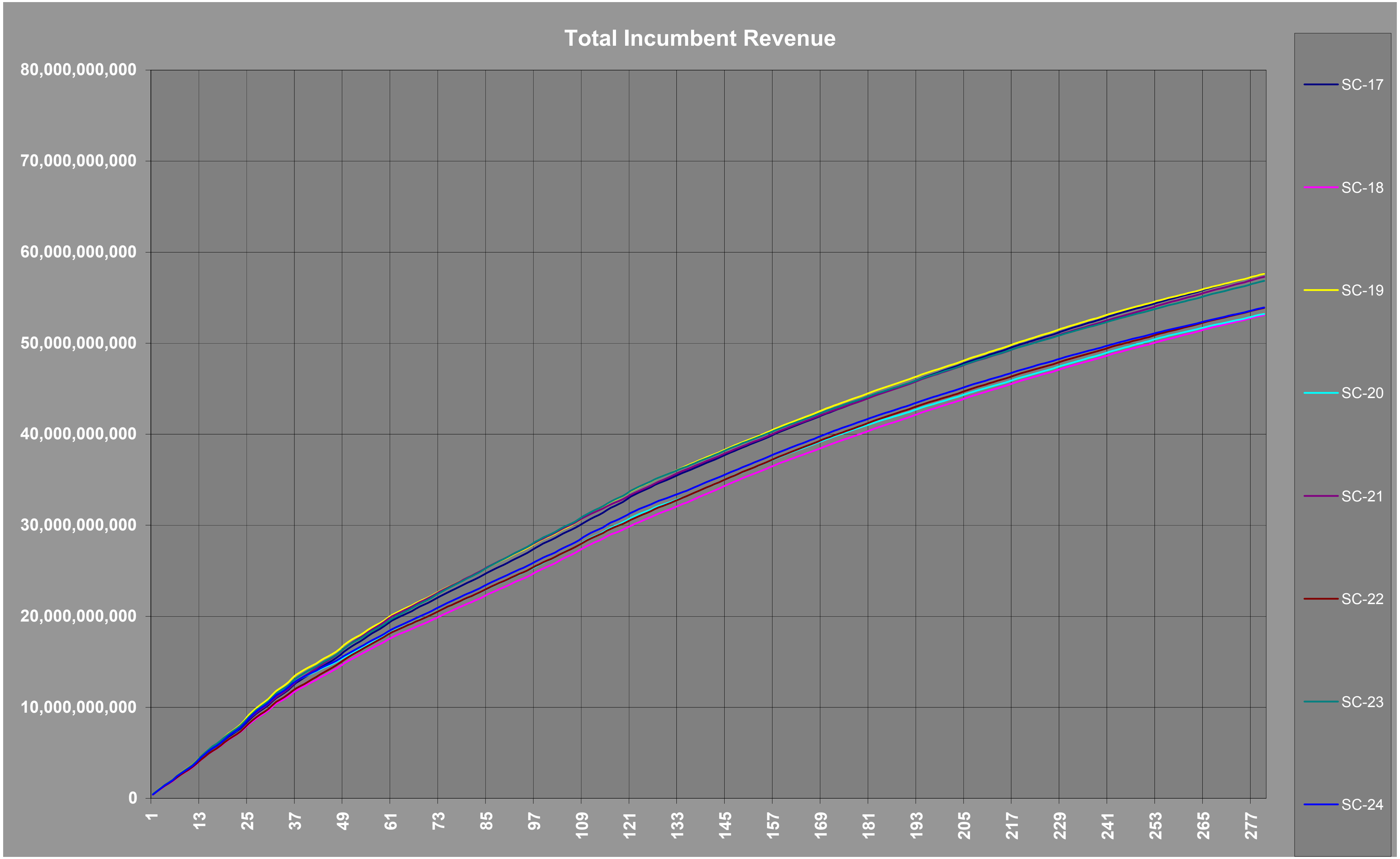
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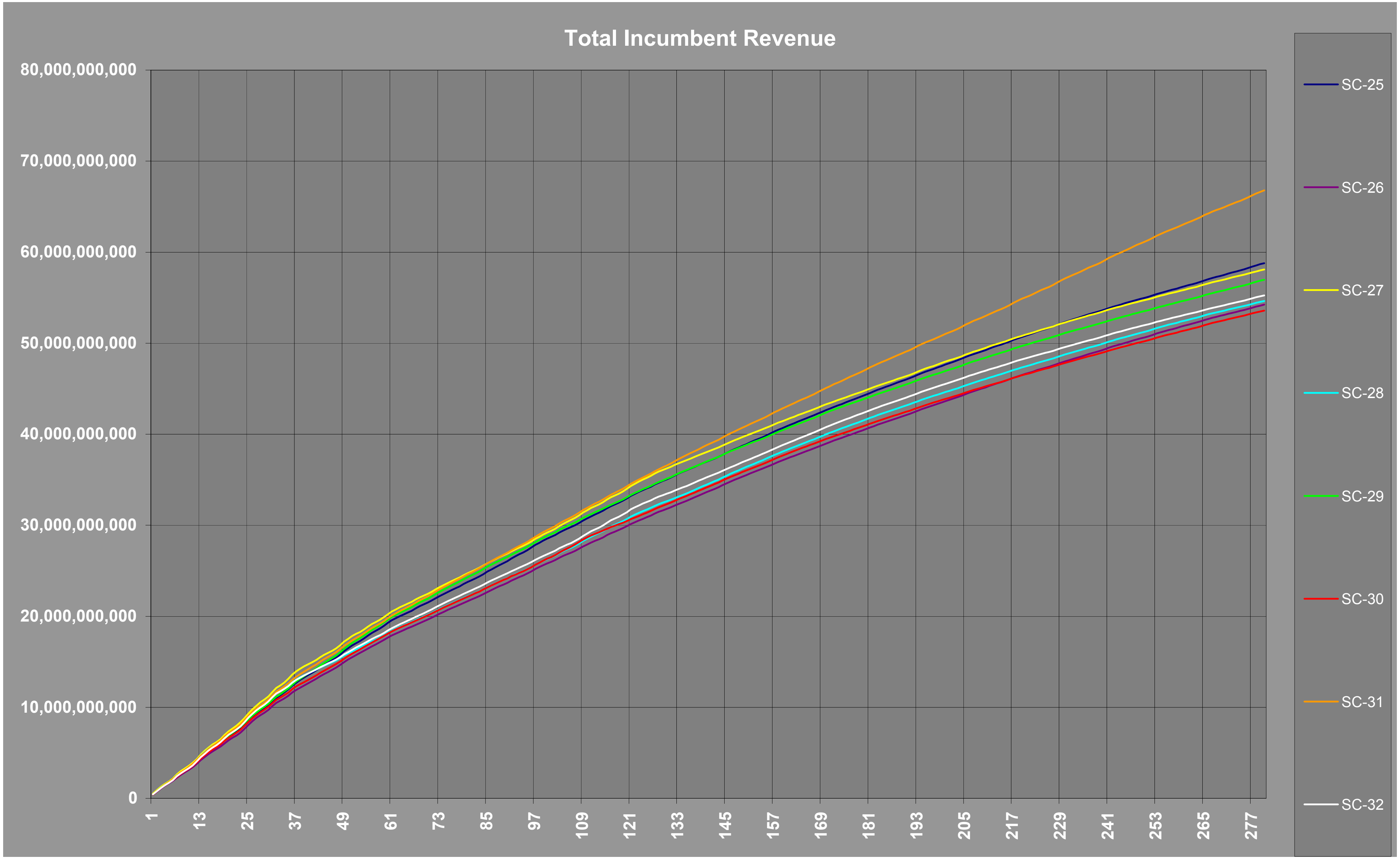

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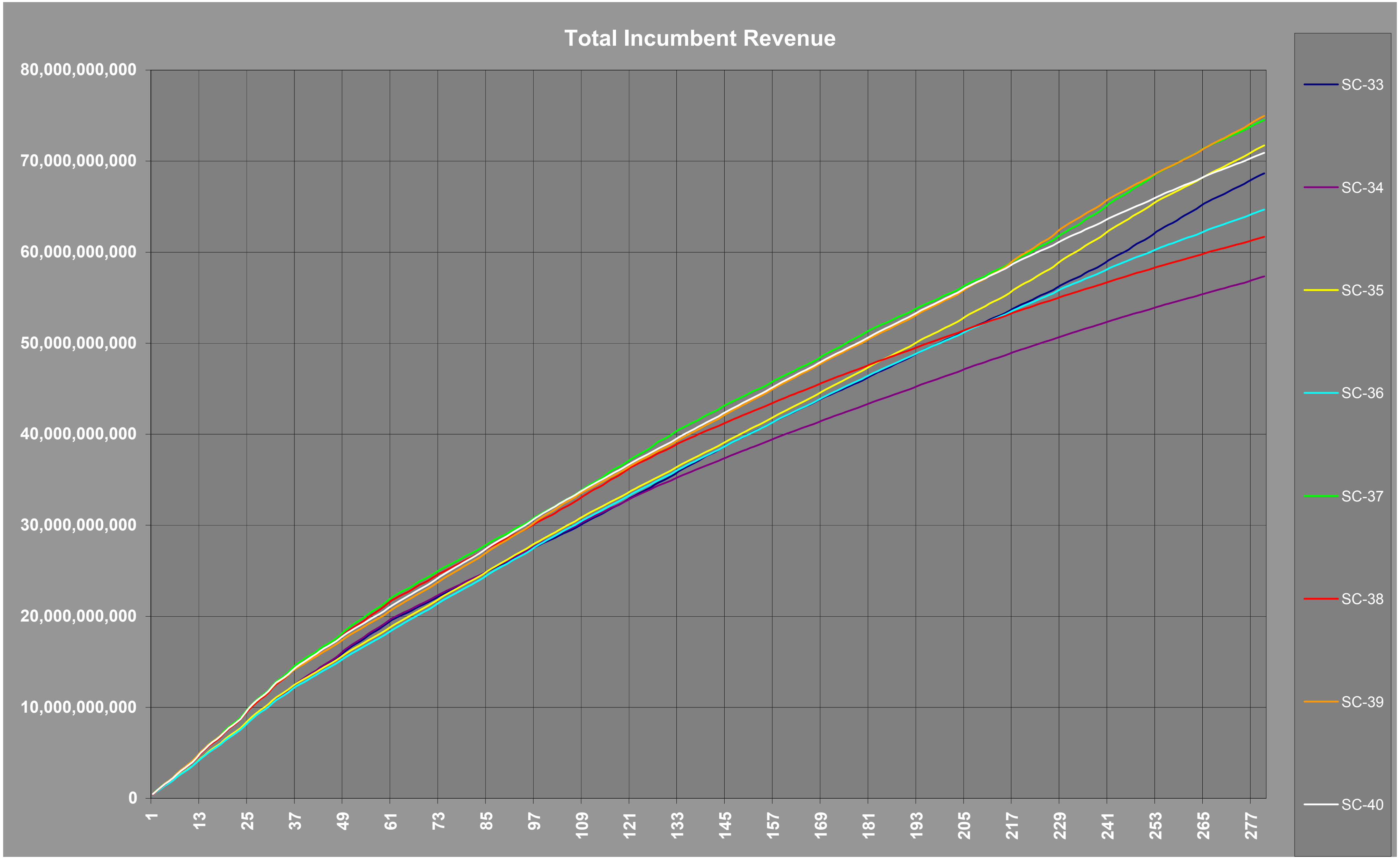

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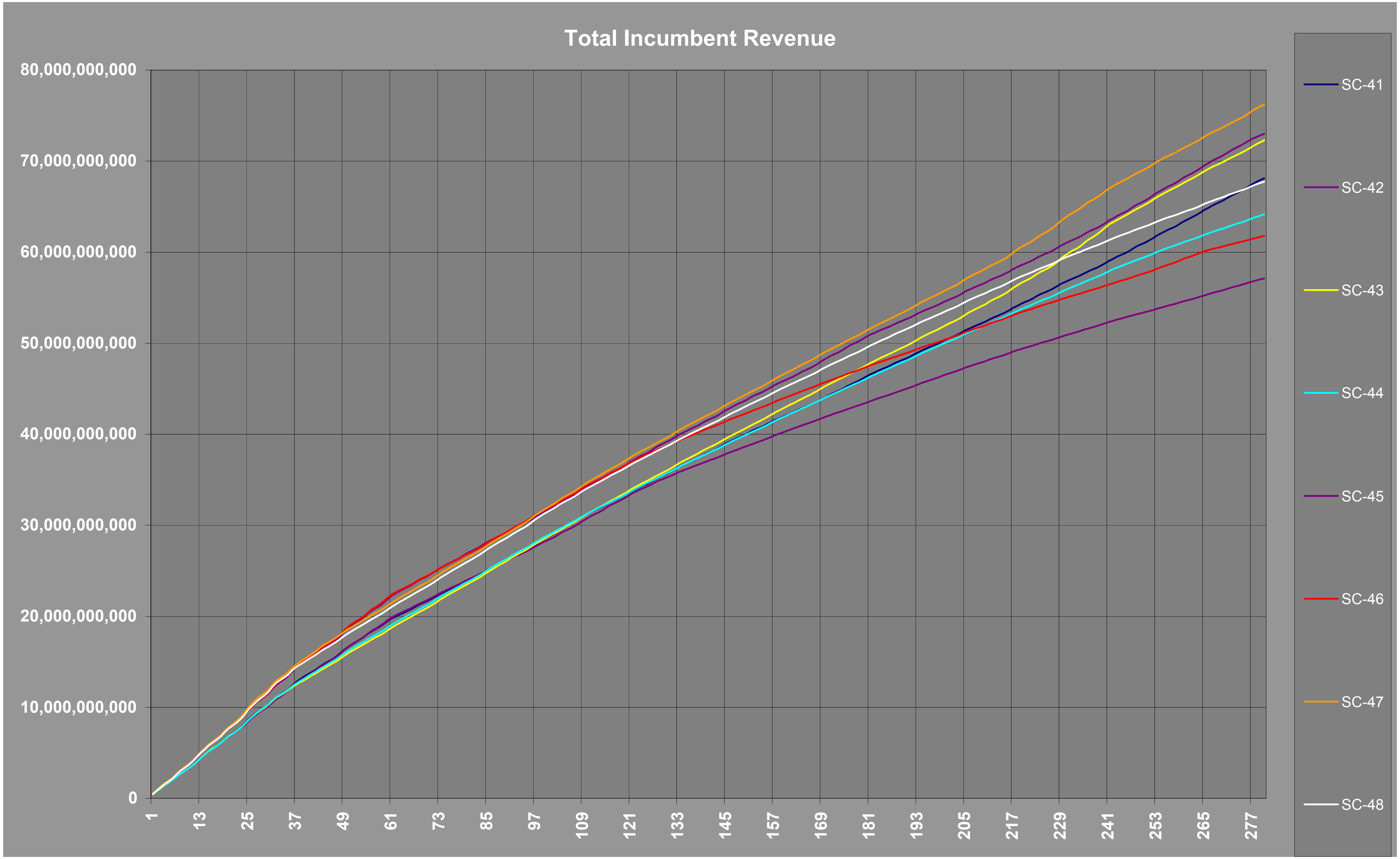

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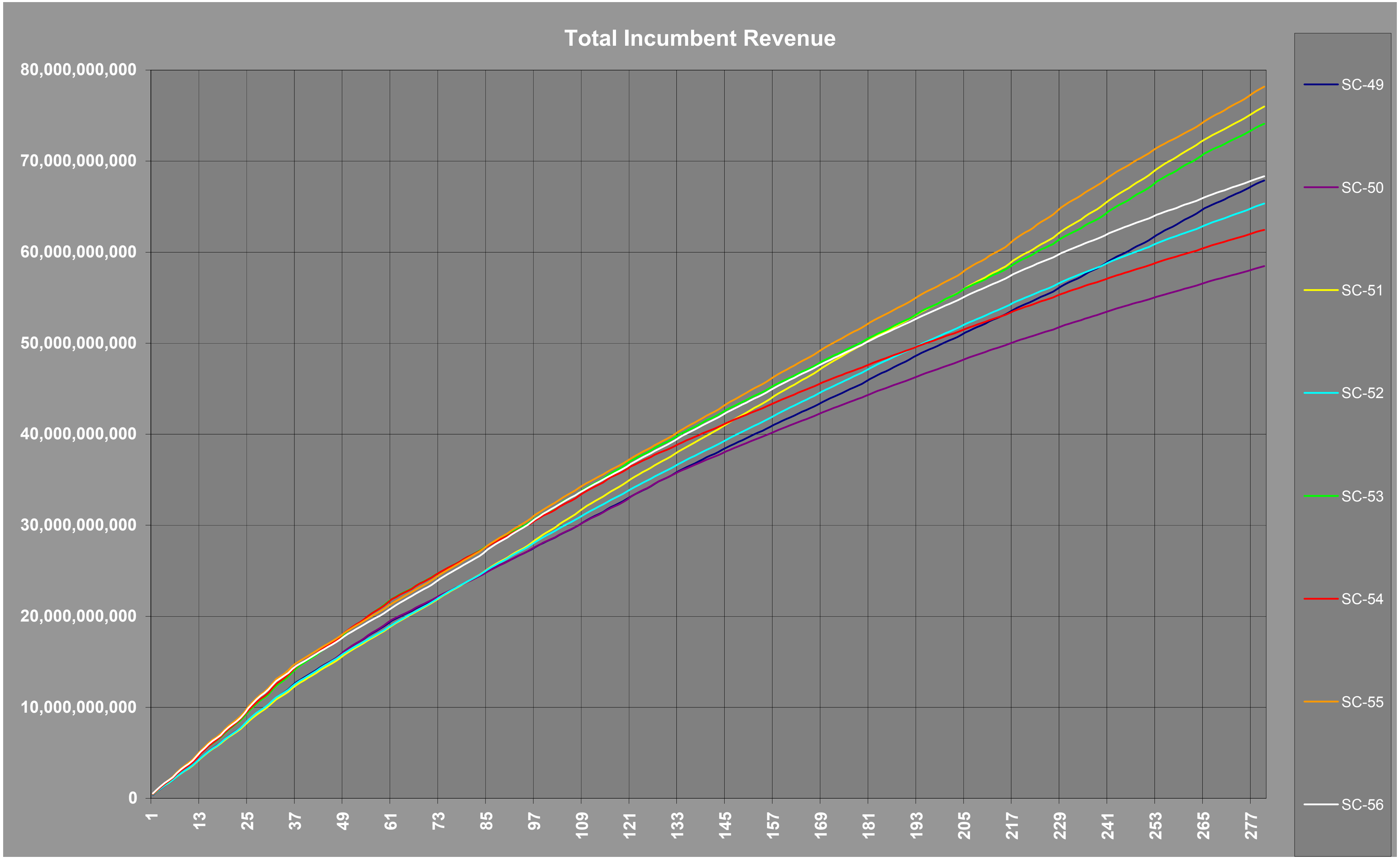
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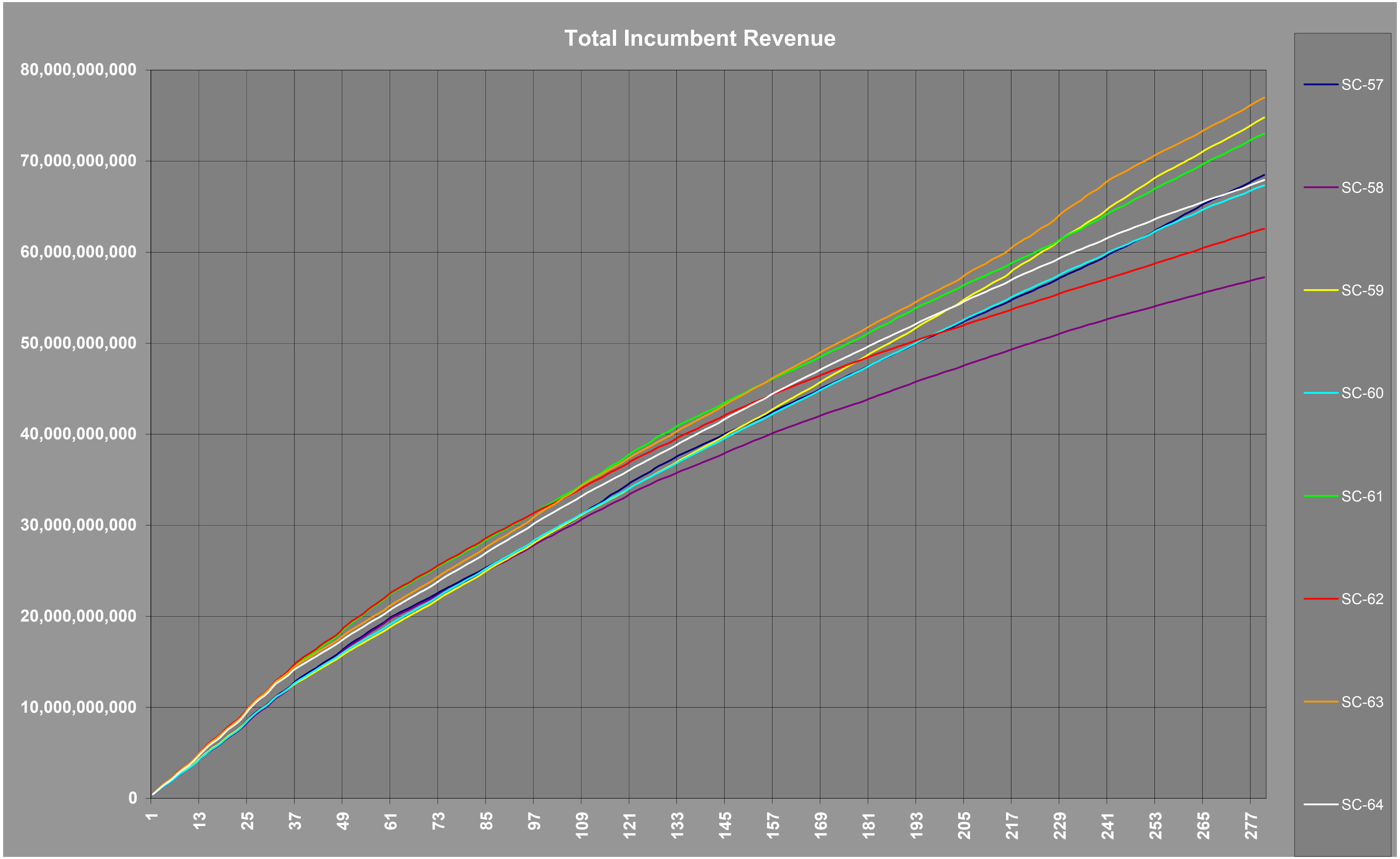

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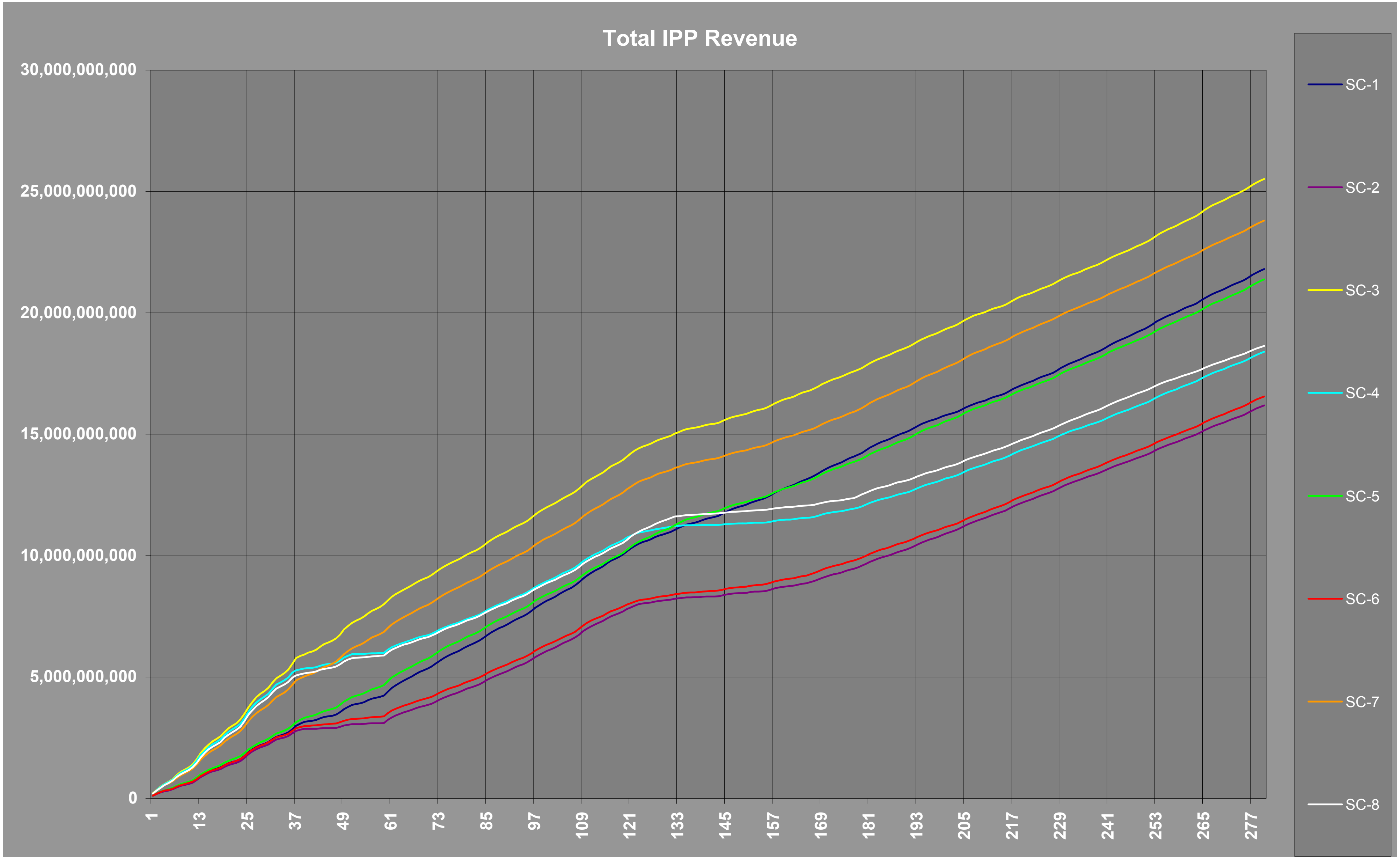
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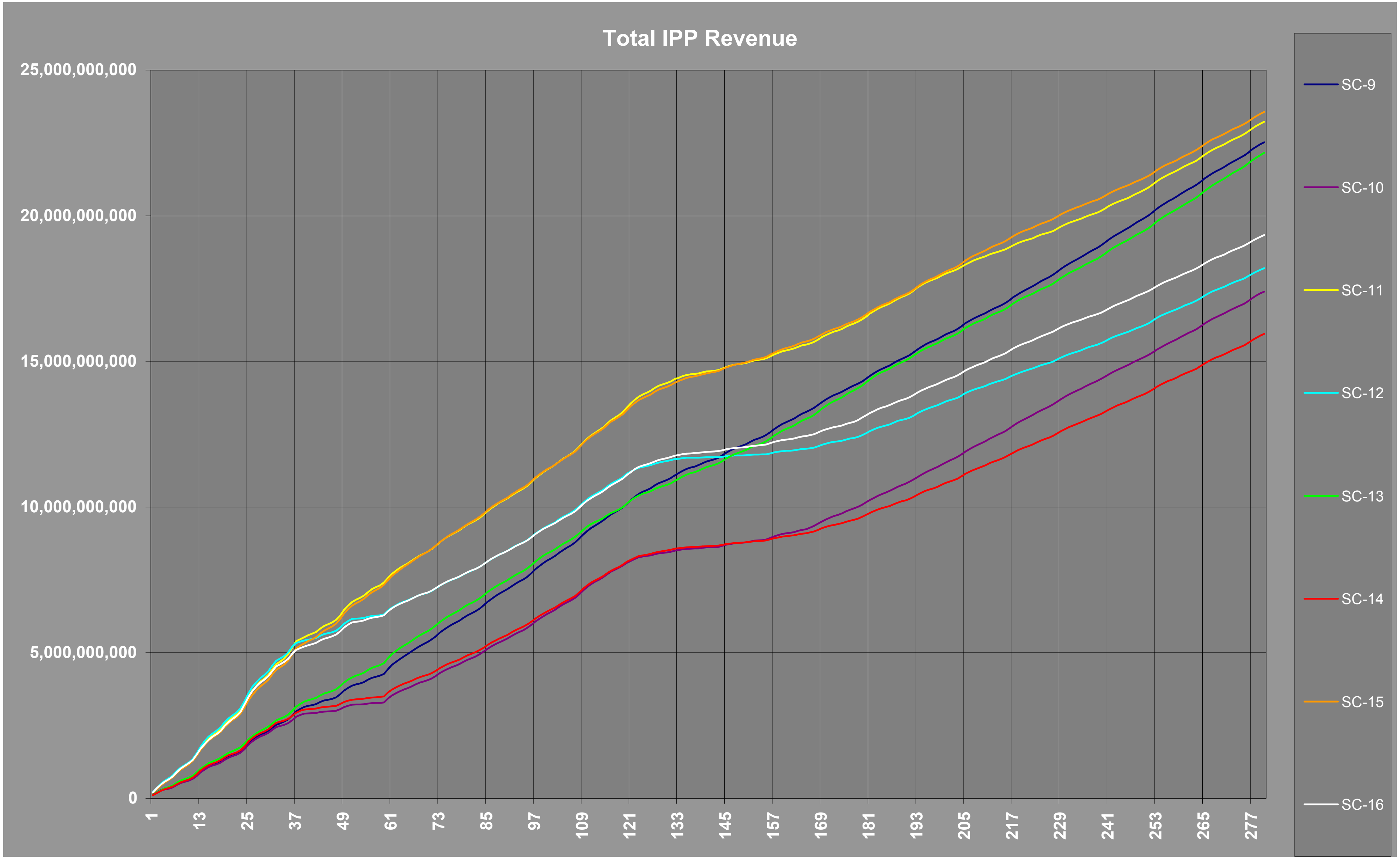

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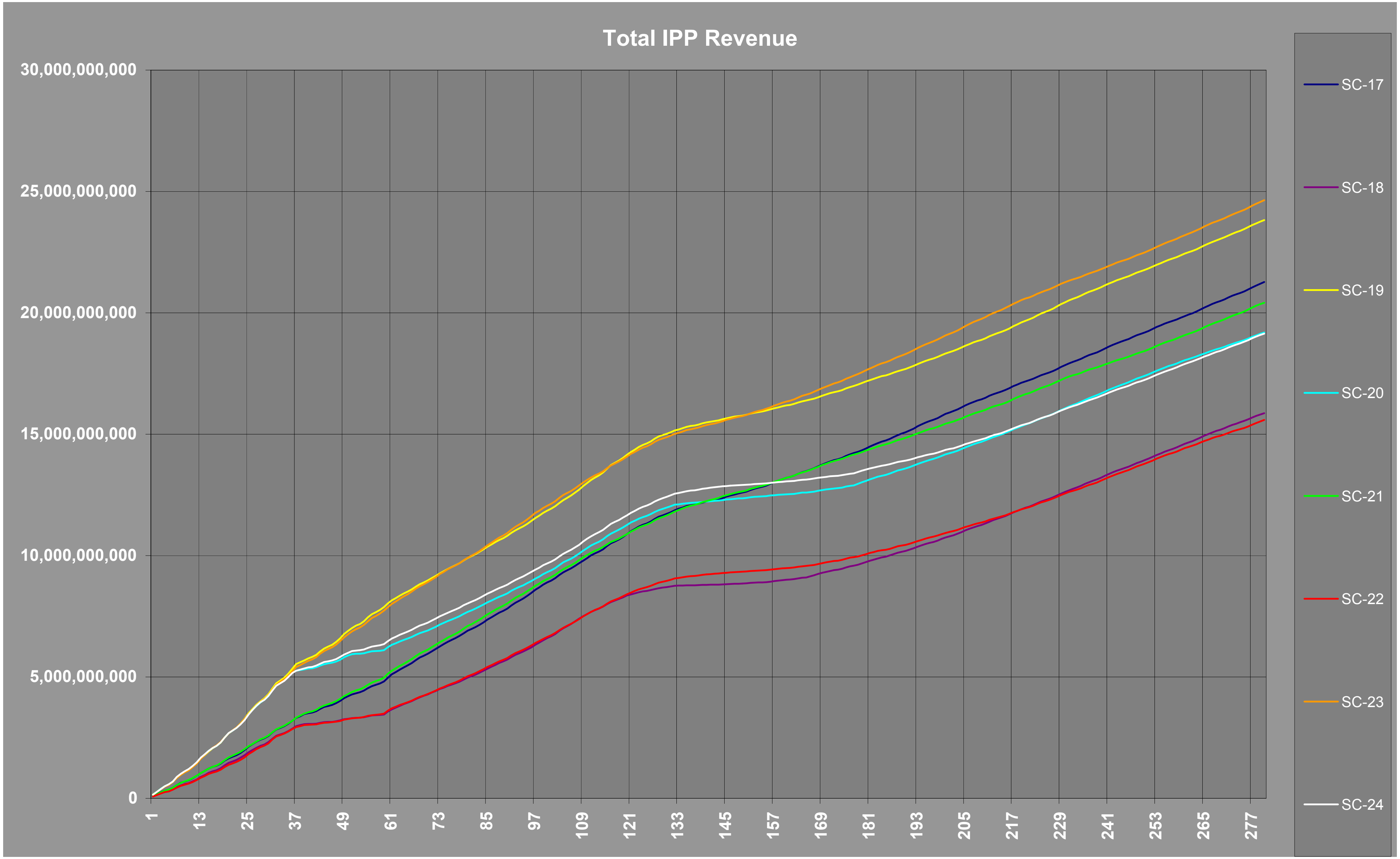

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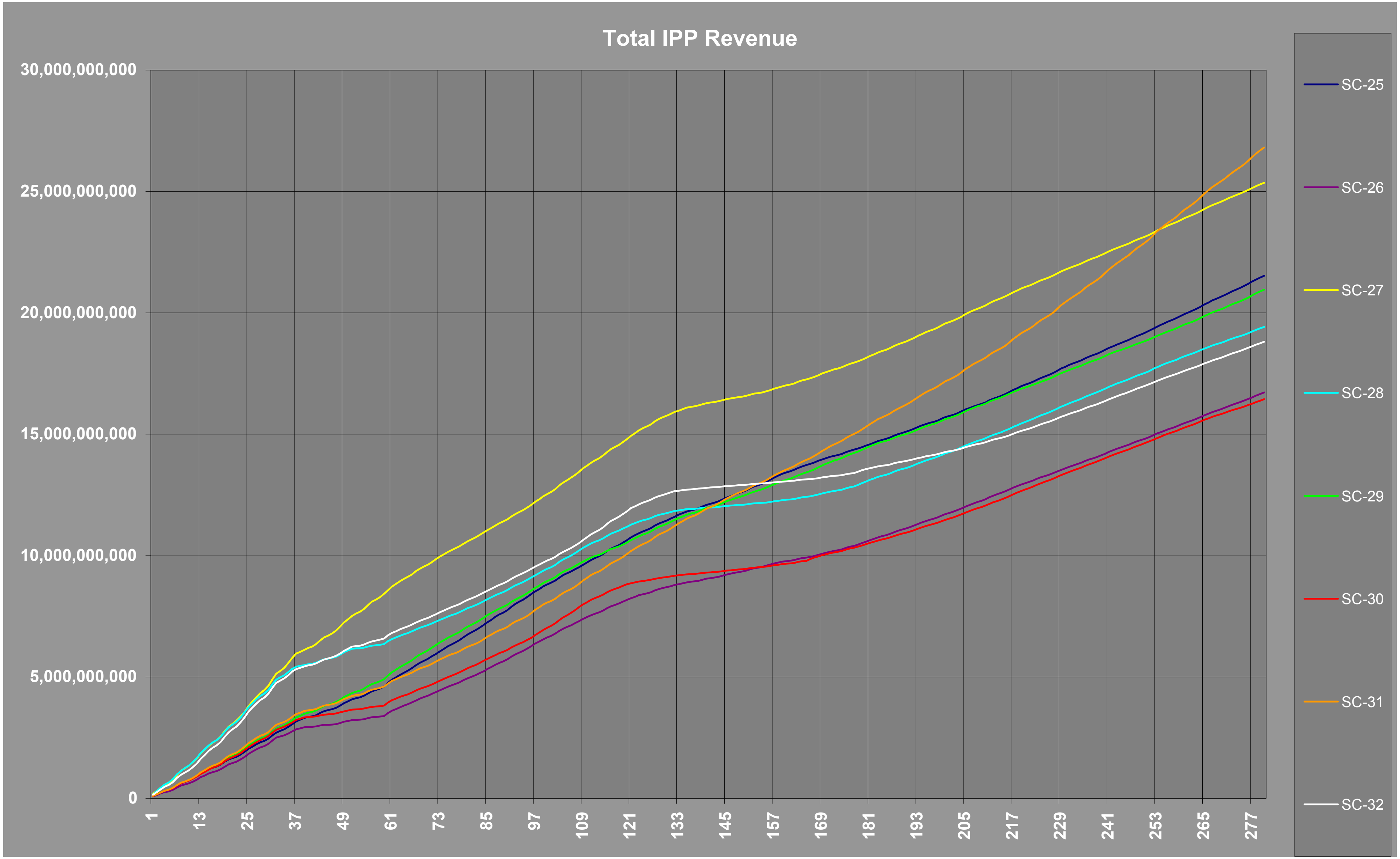

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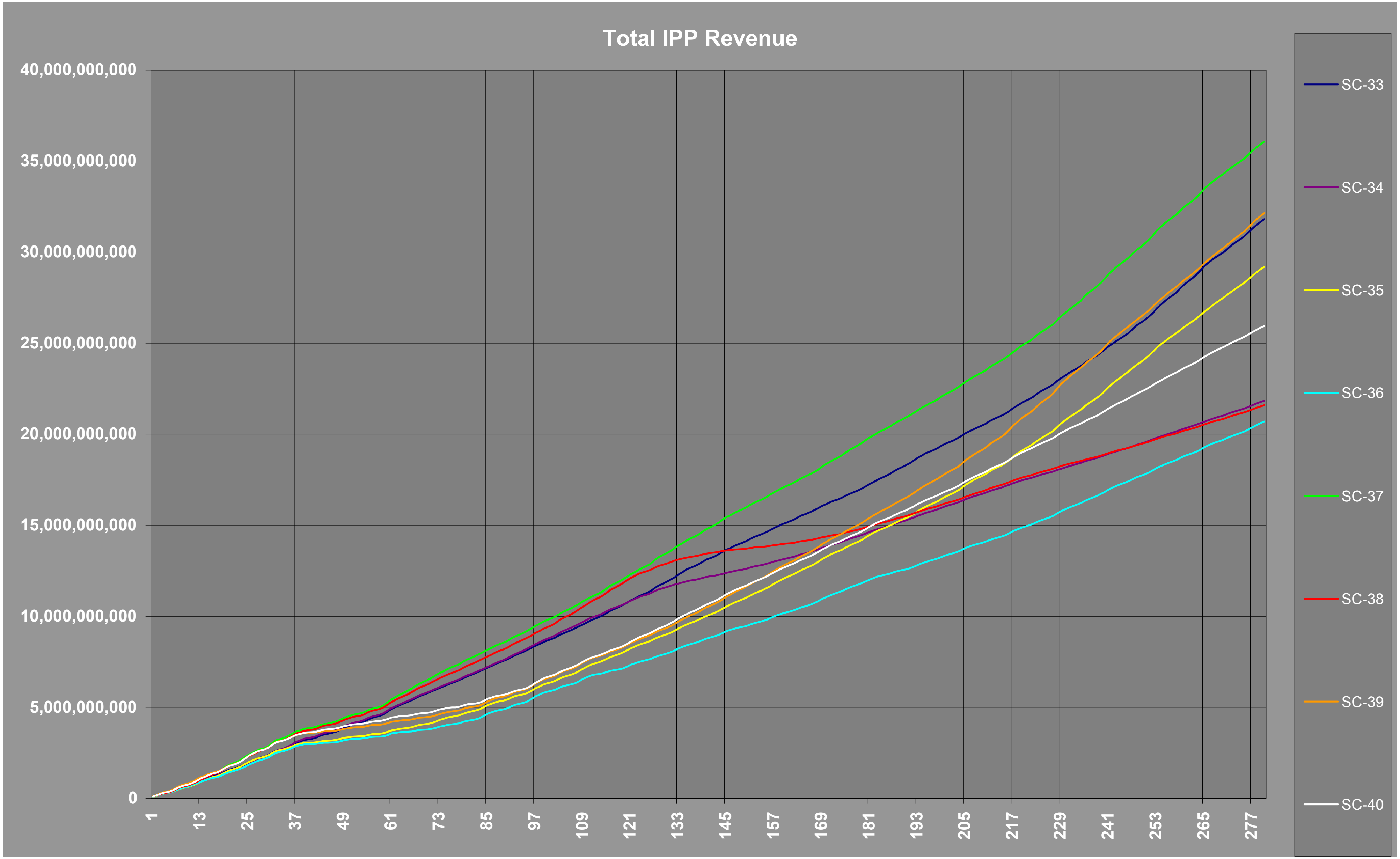

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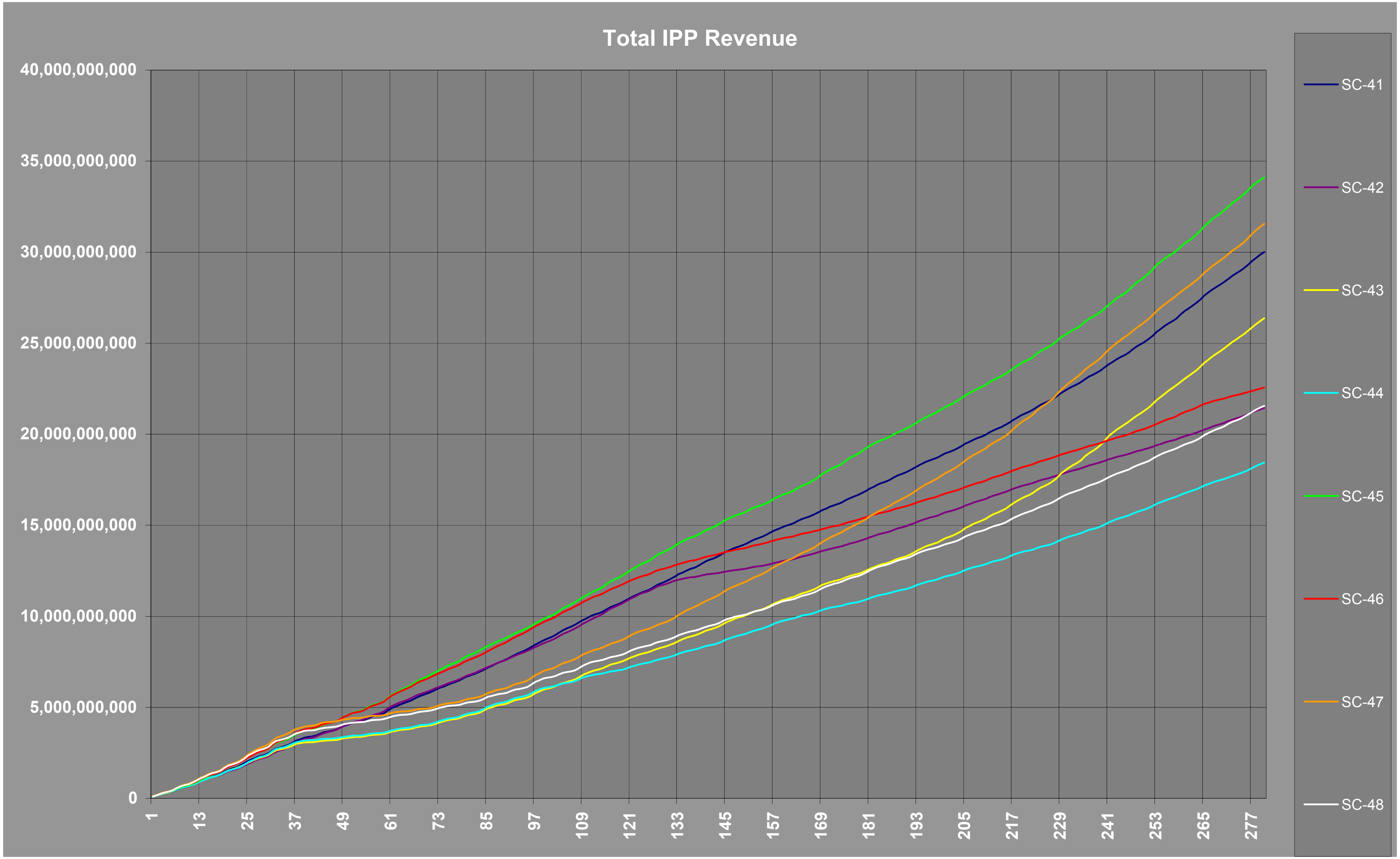

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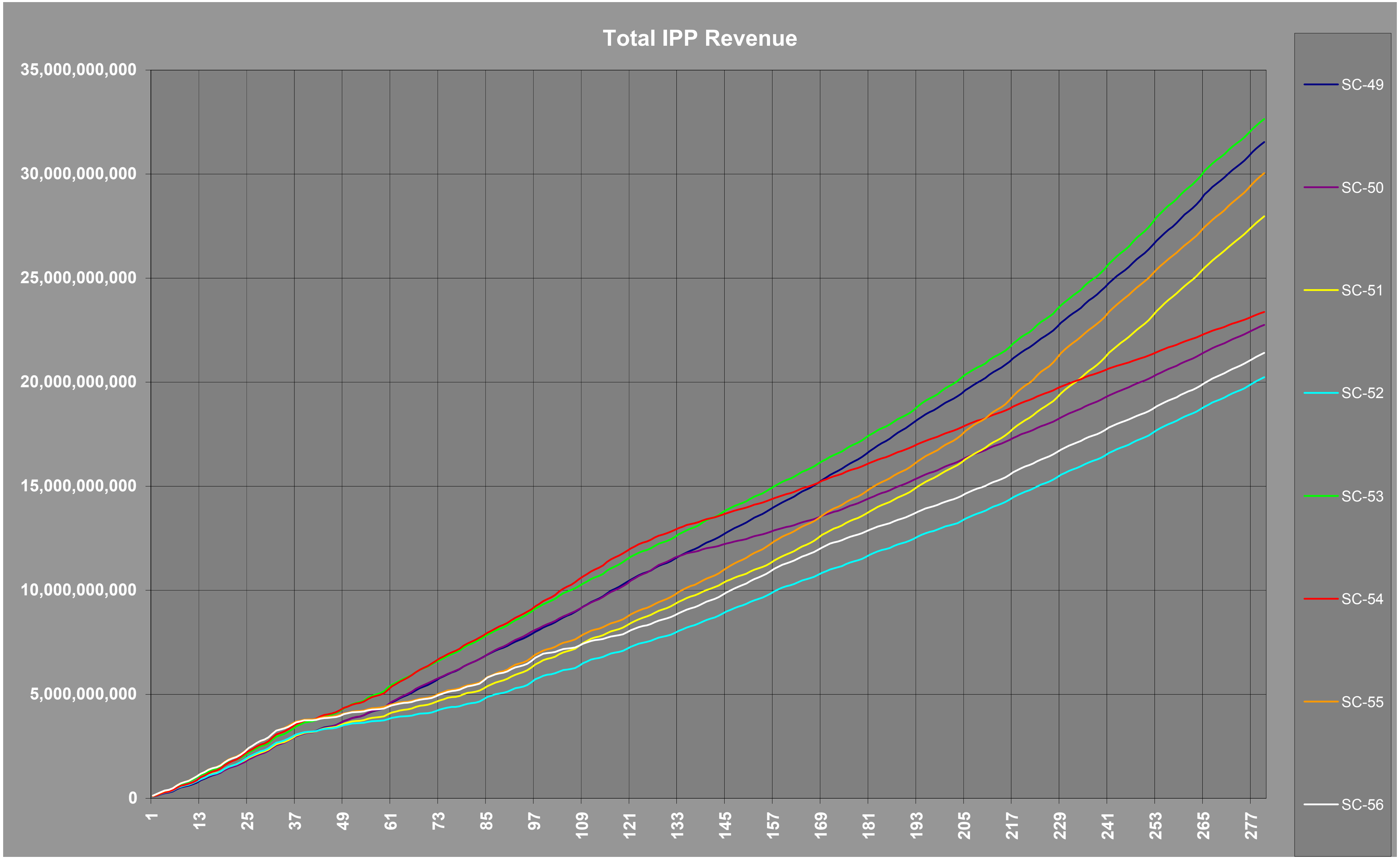
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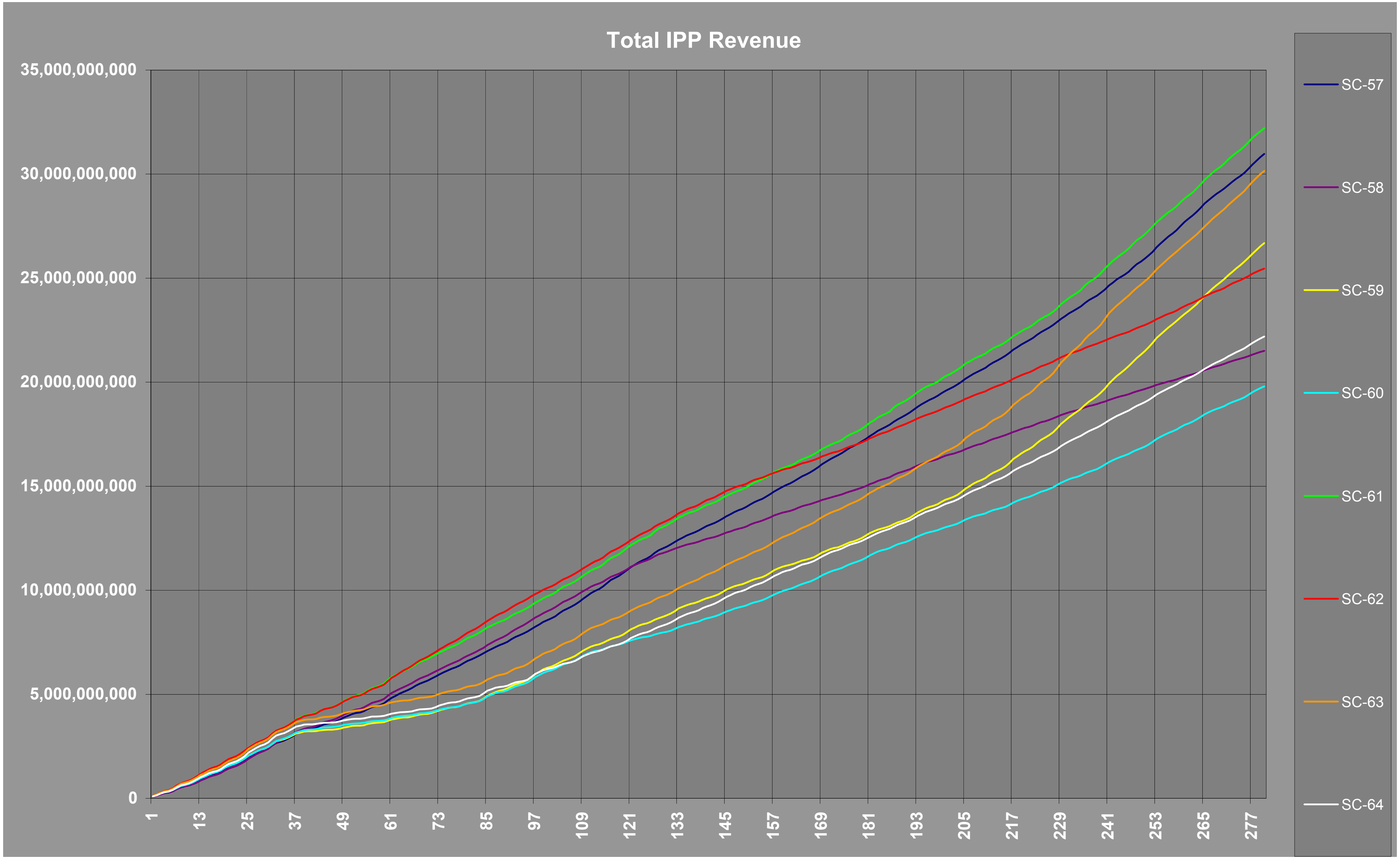
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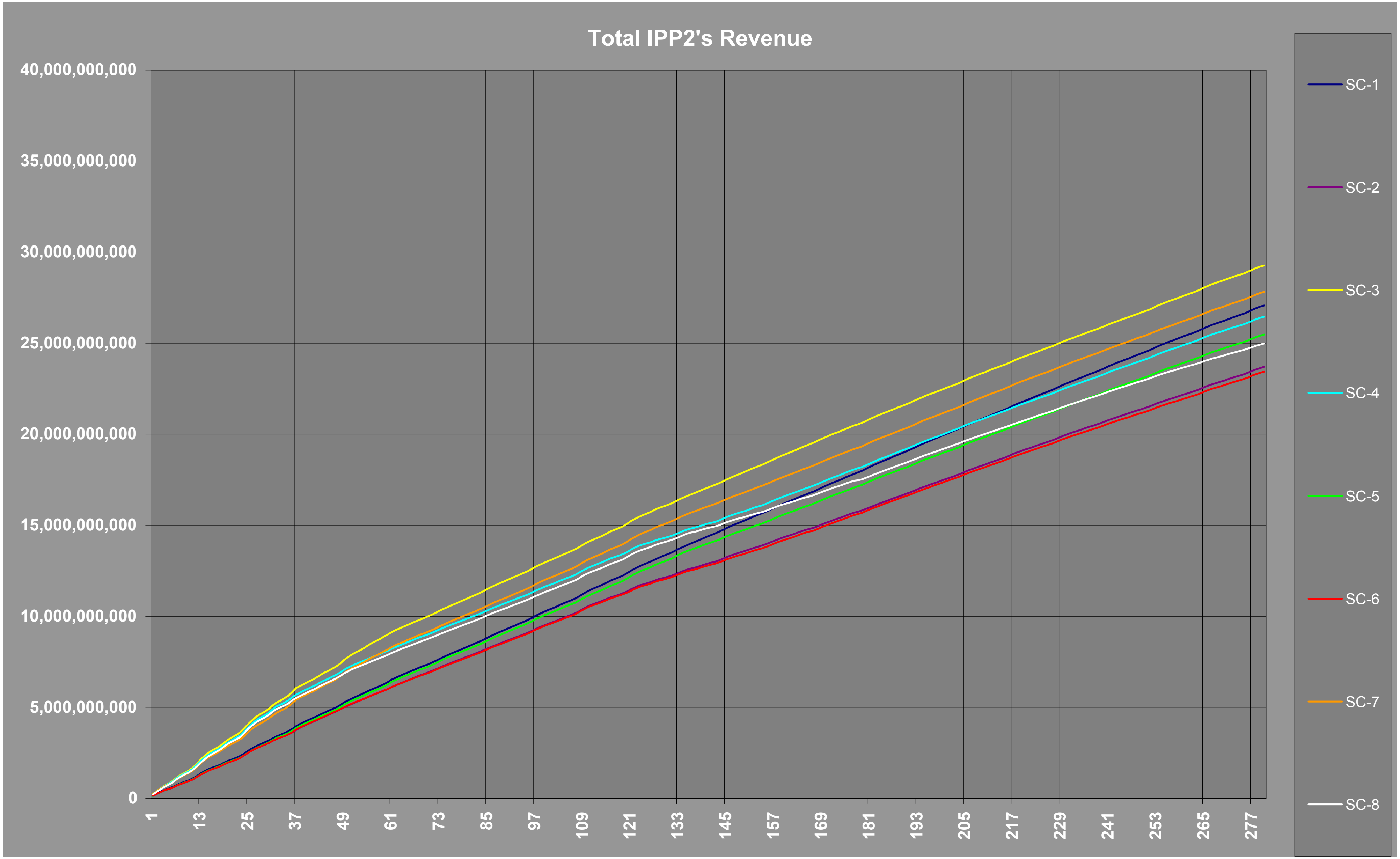
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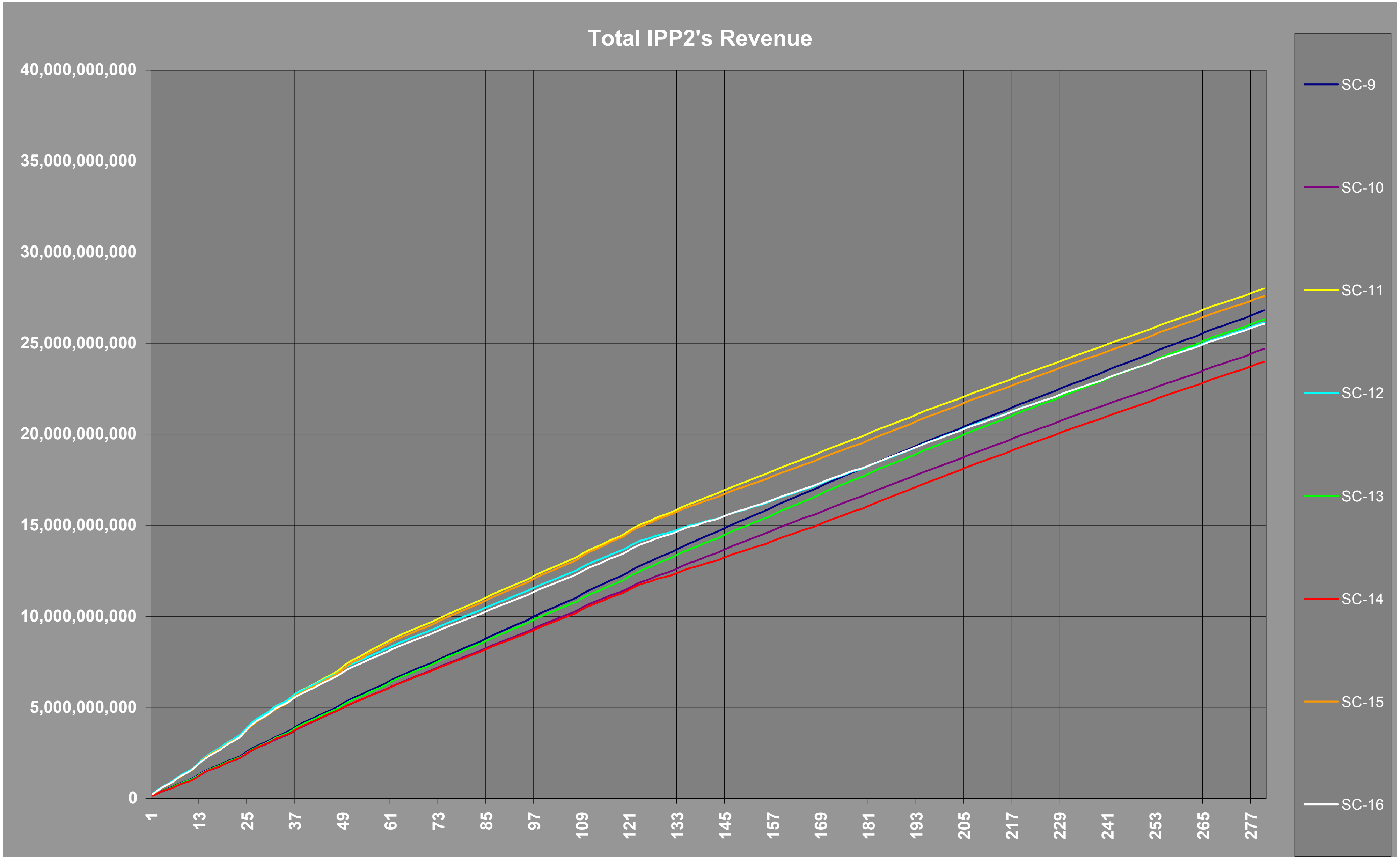
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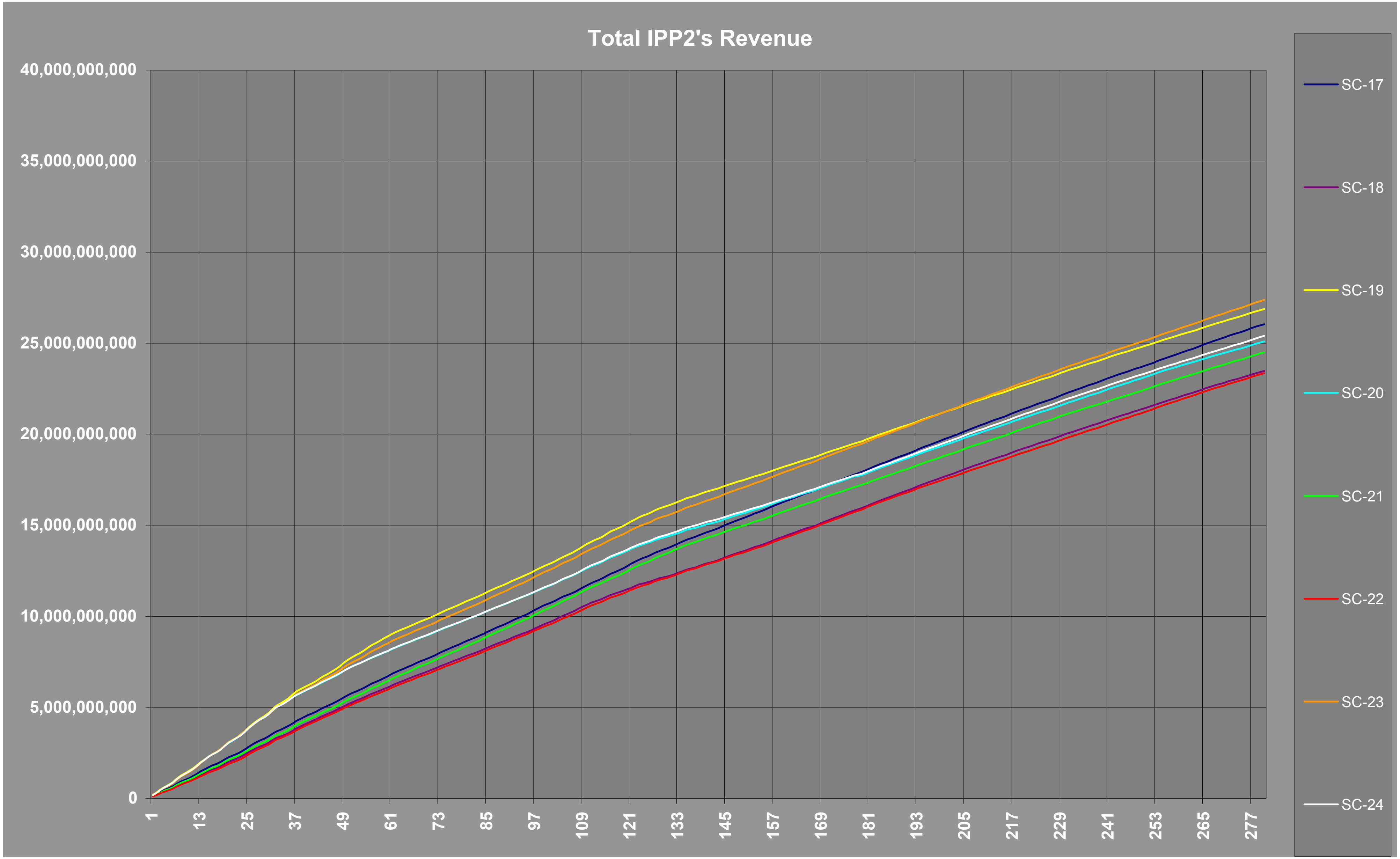

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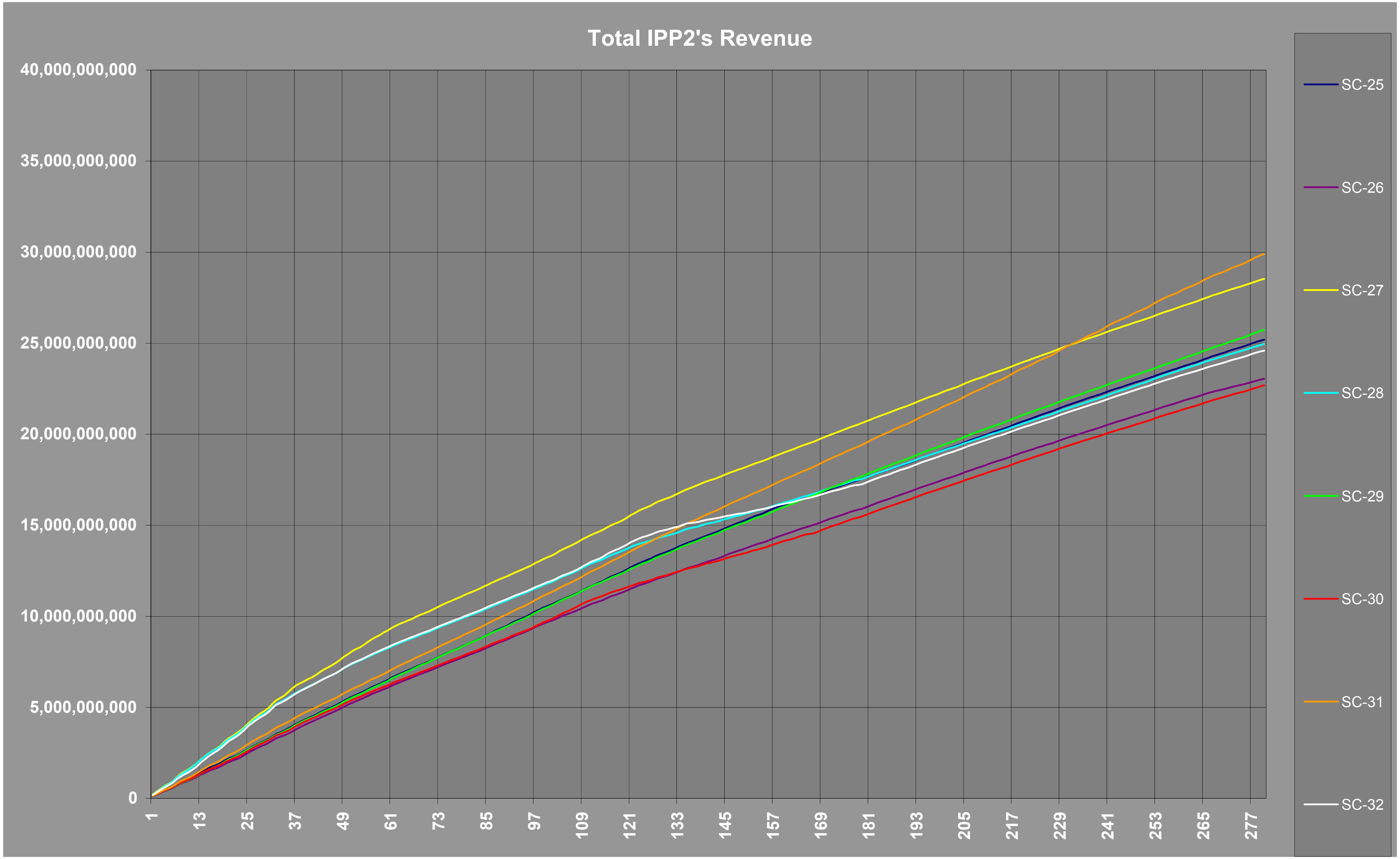

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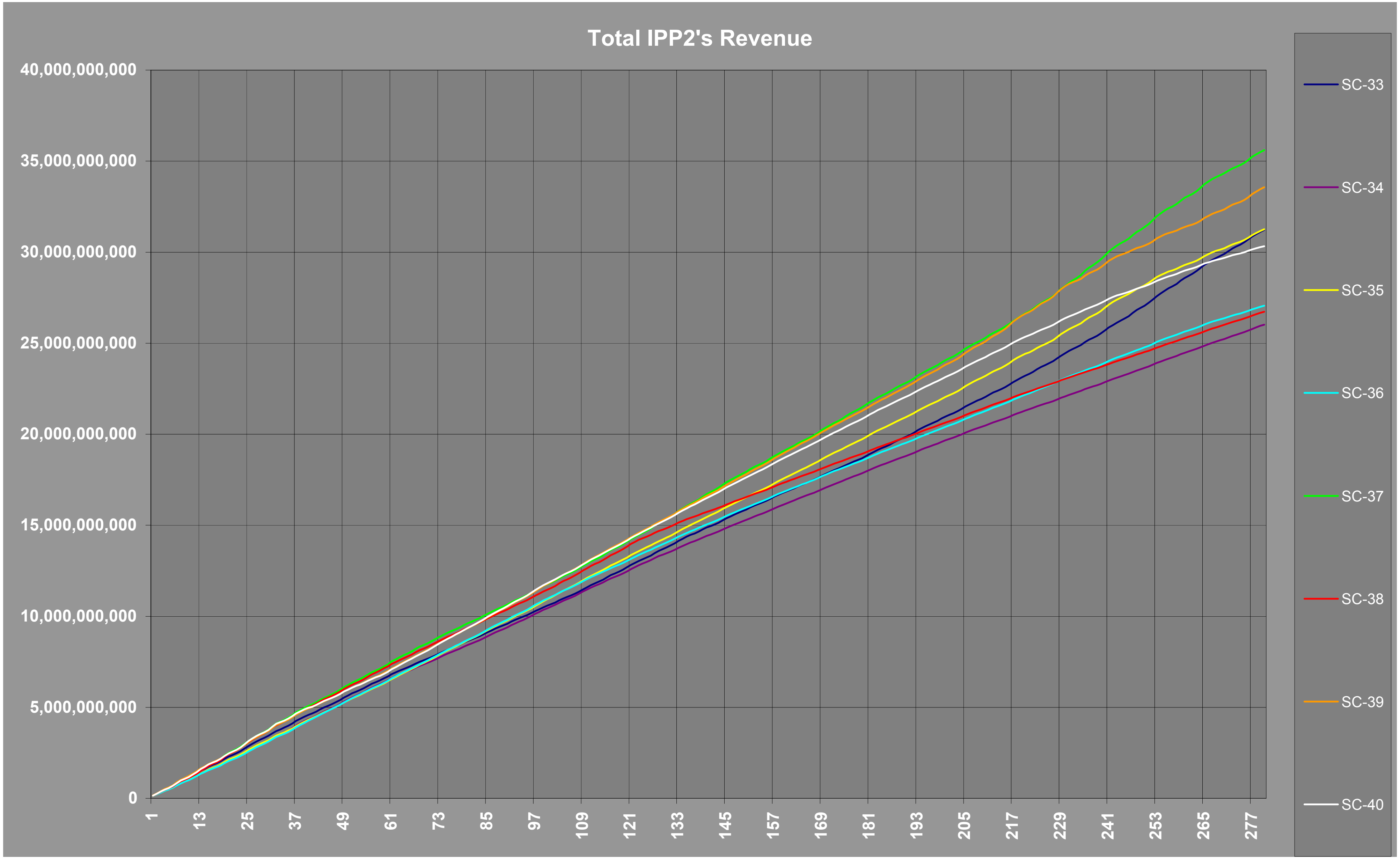

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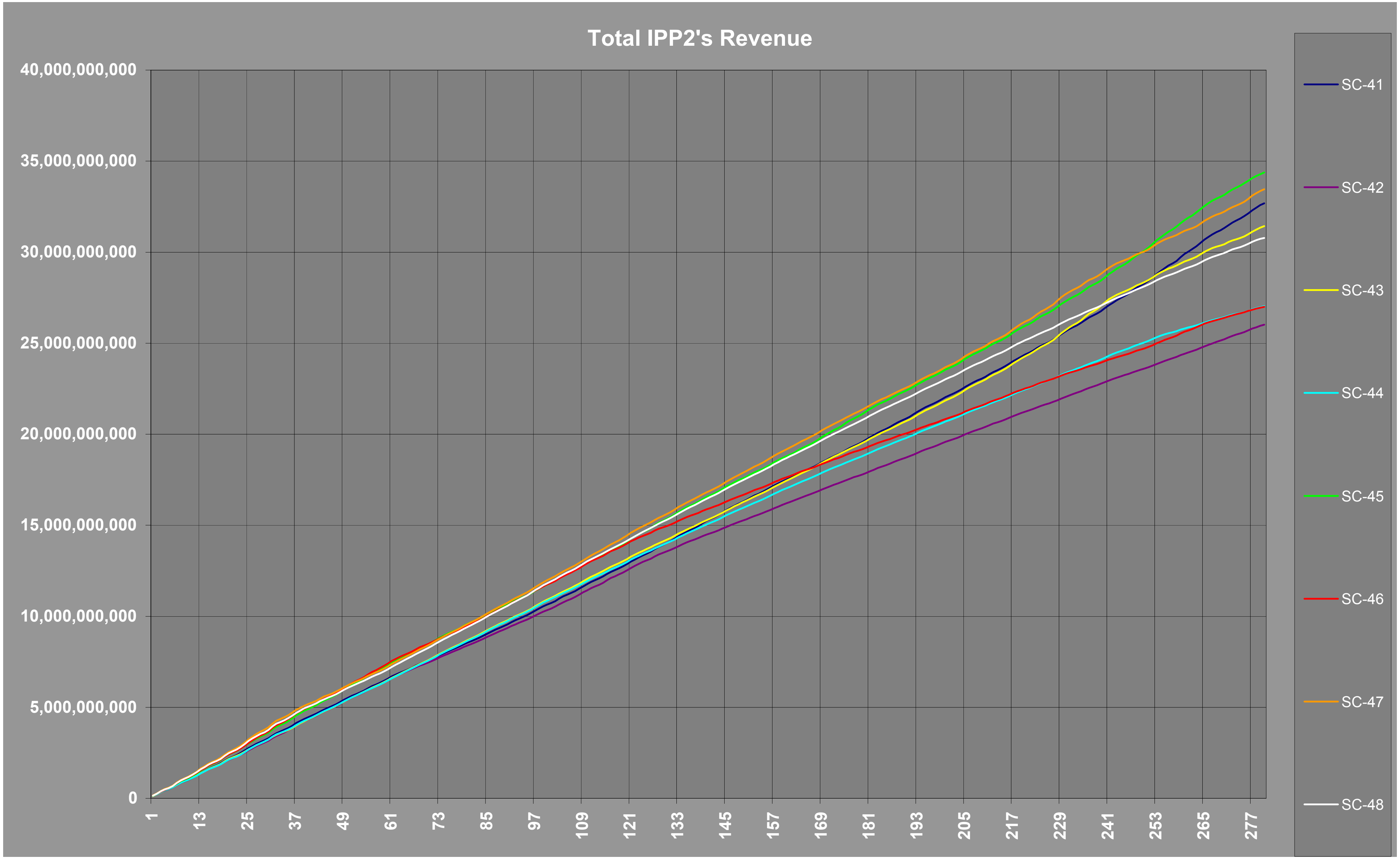

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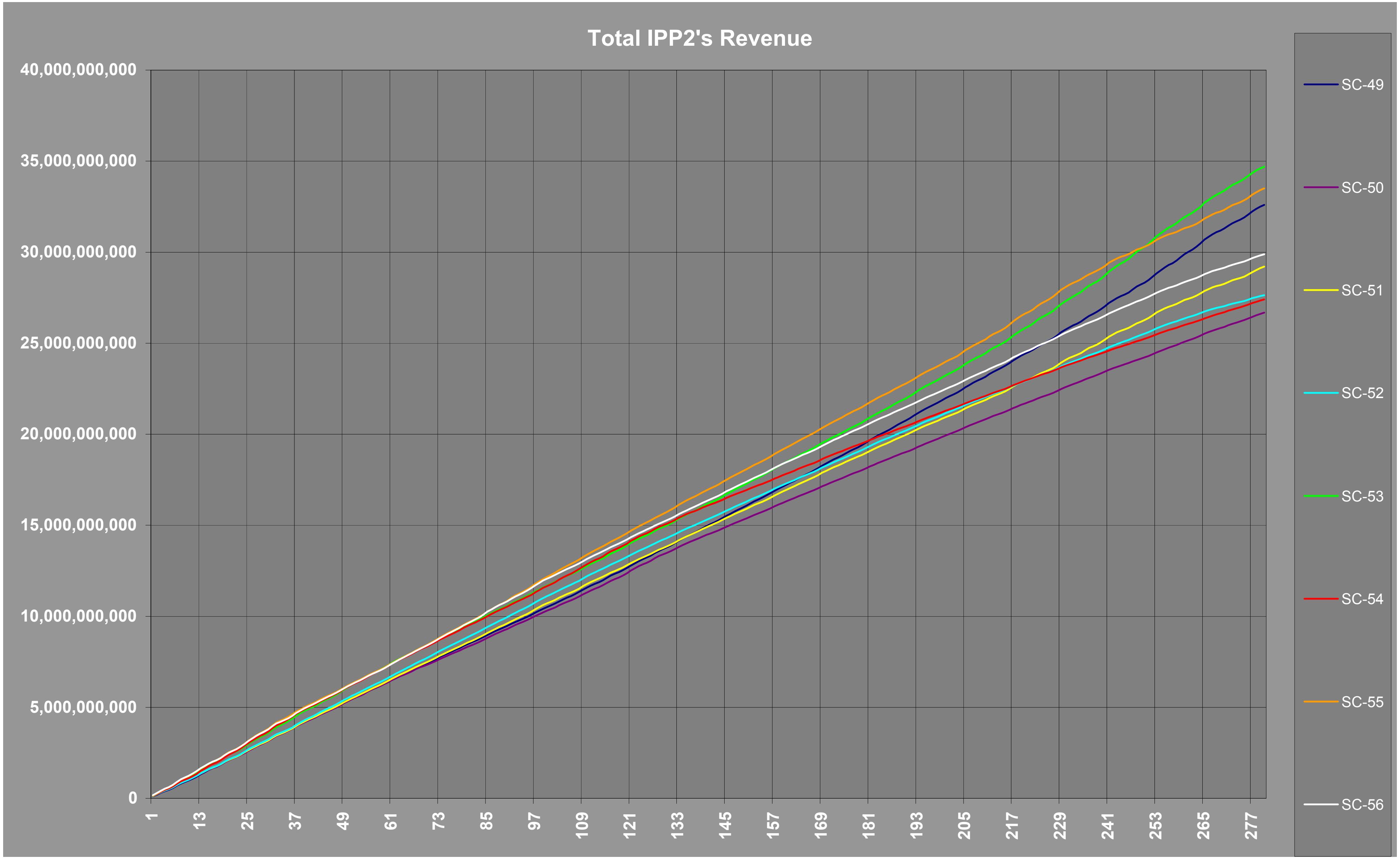
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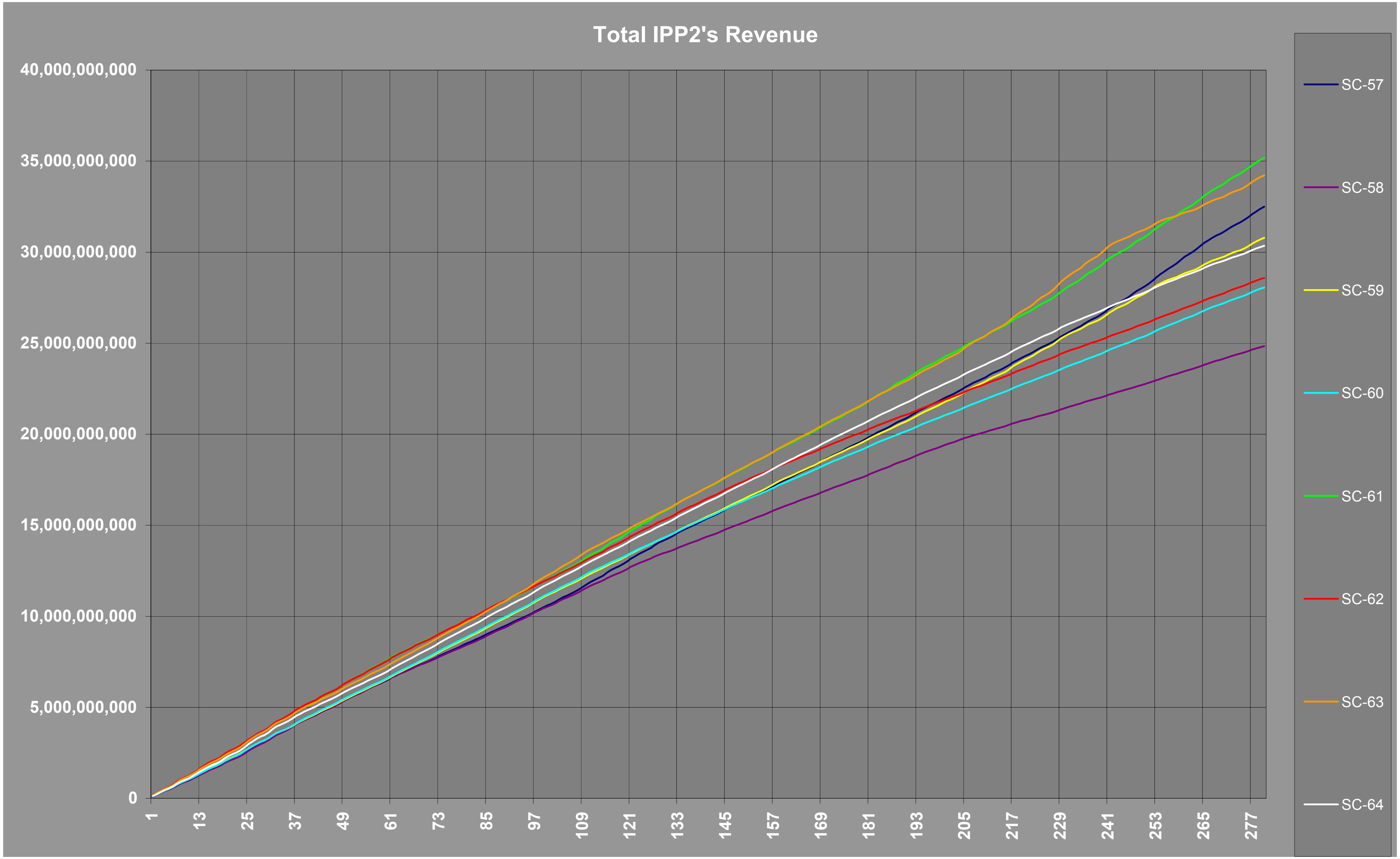

Total IPP2's Revenue
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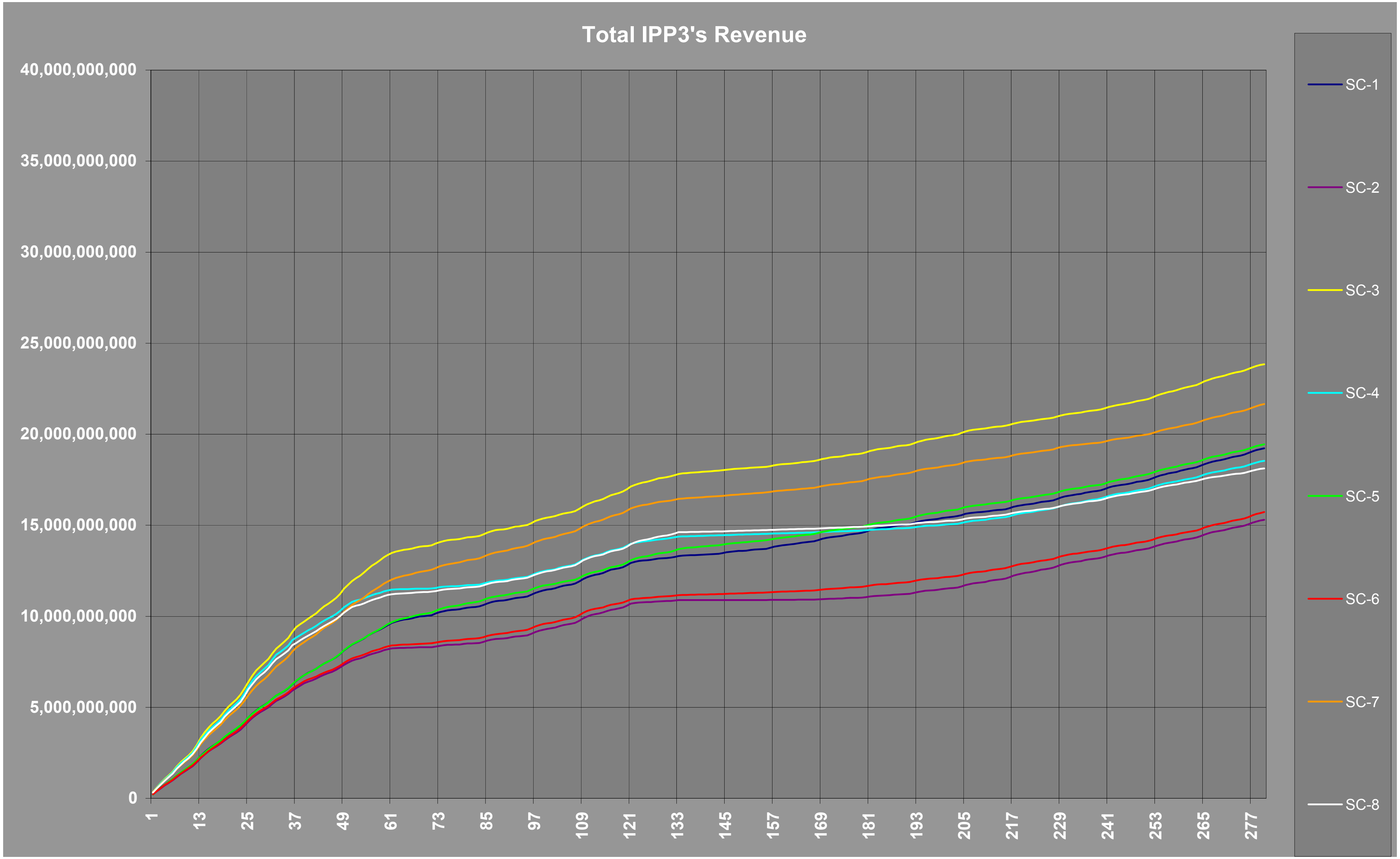

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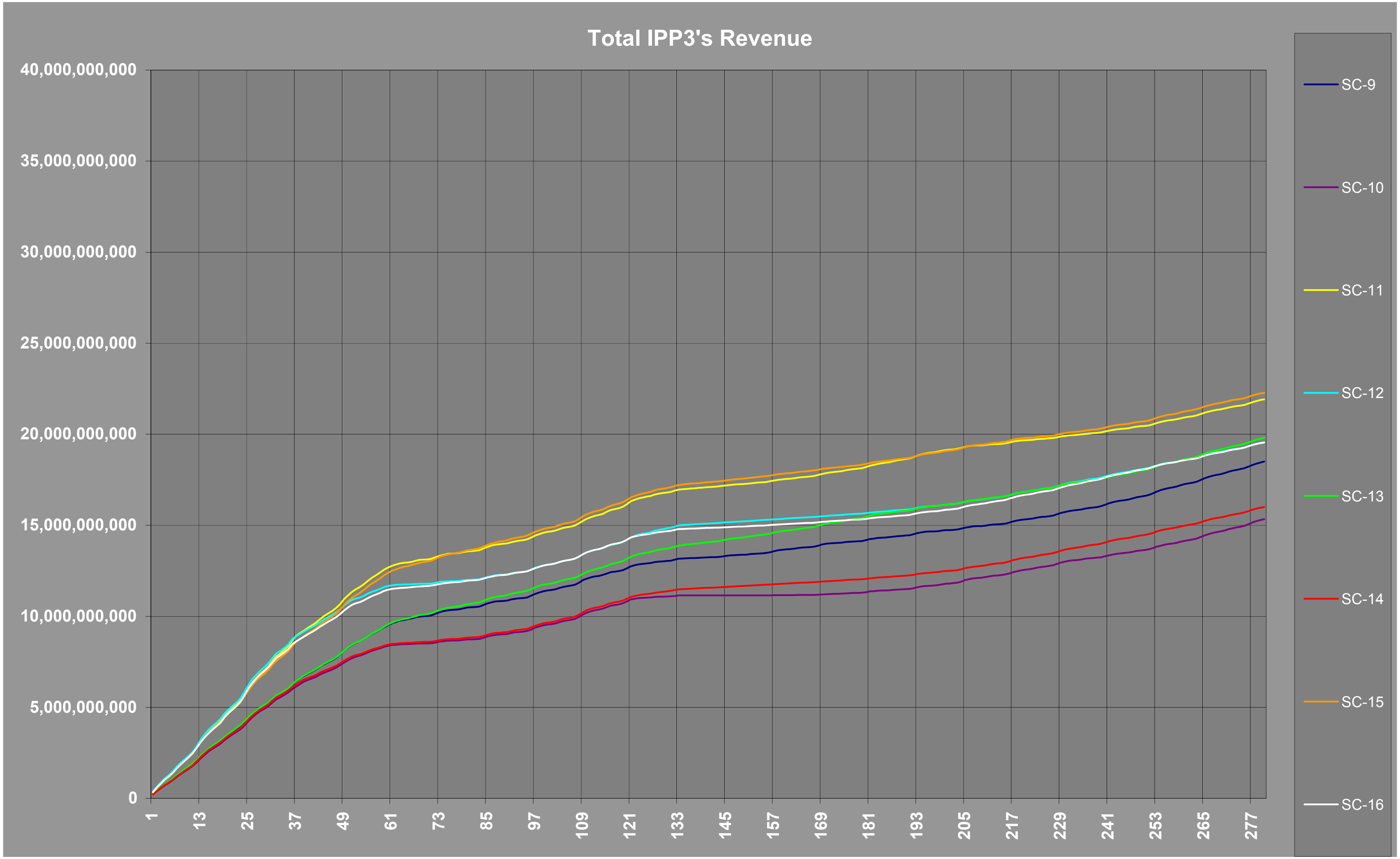

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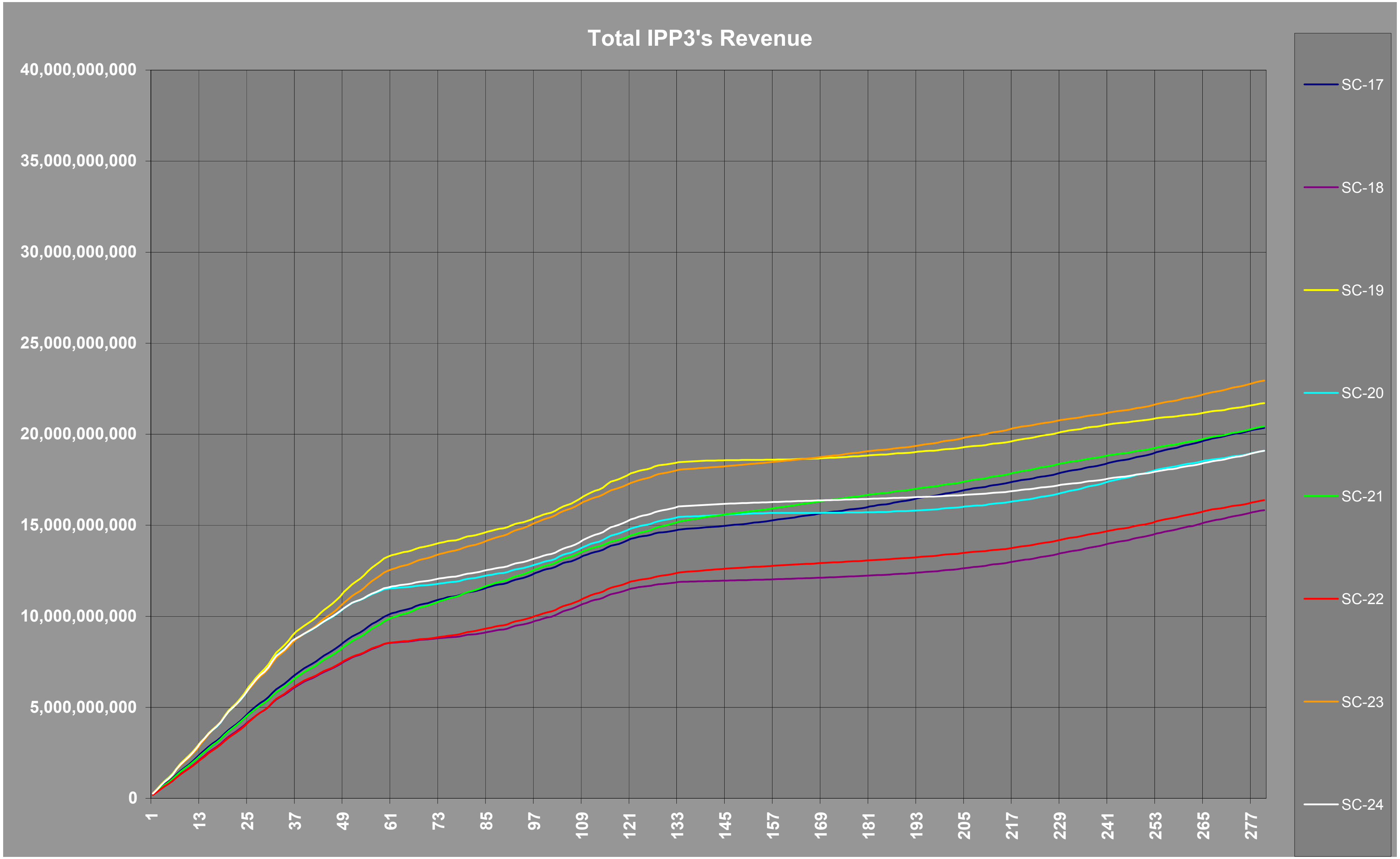

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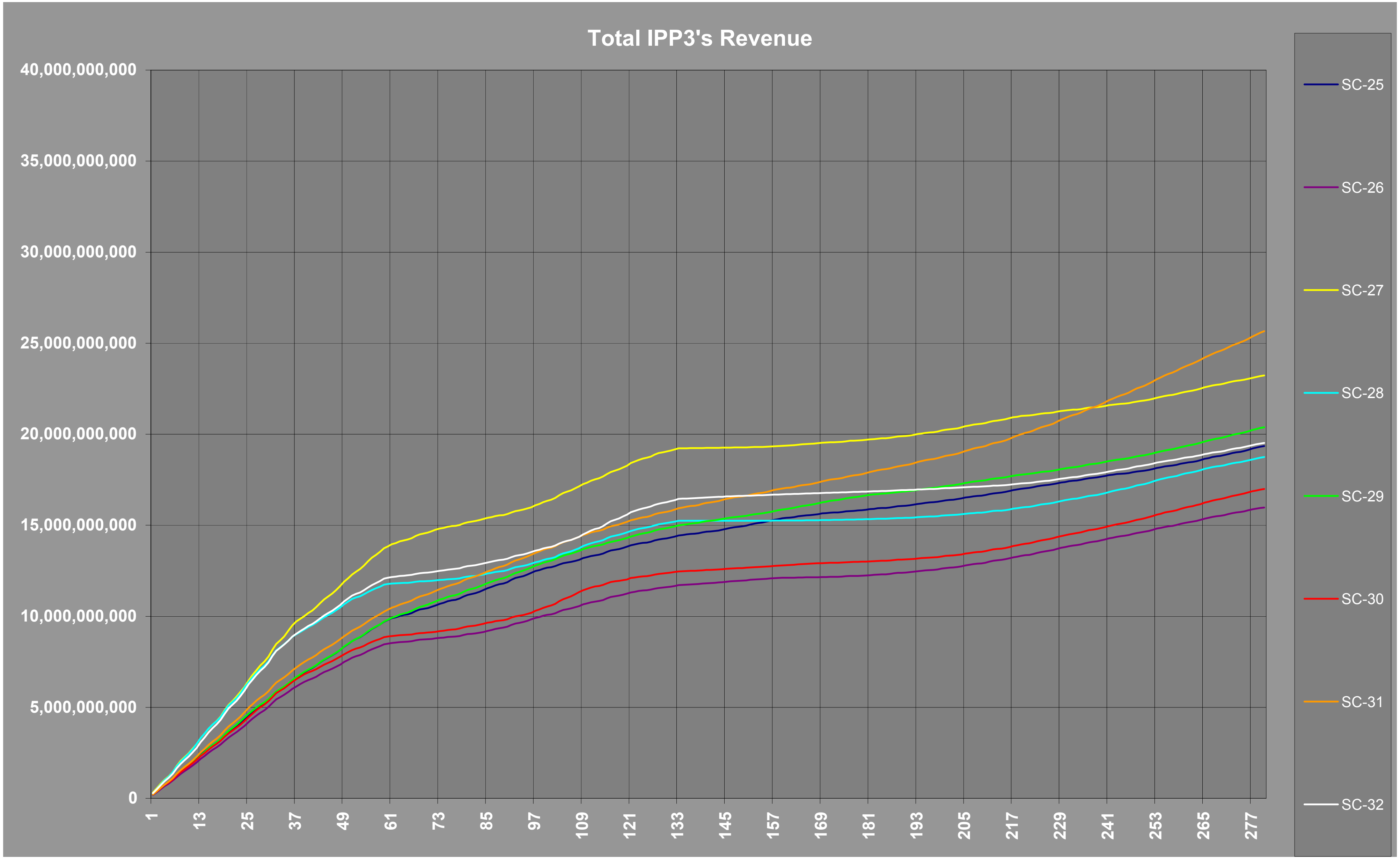
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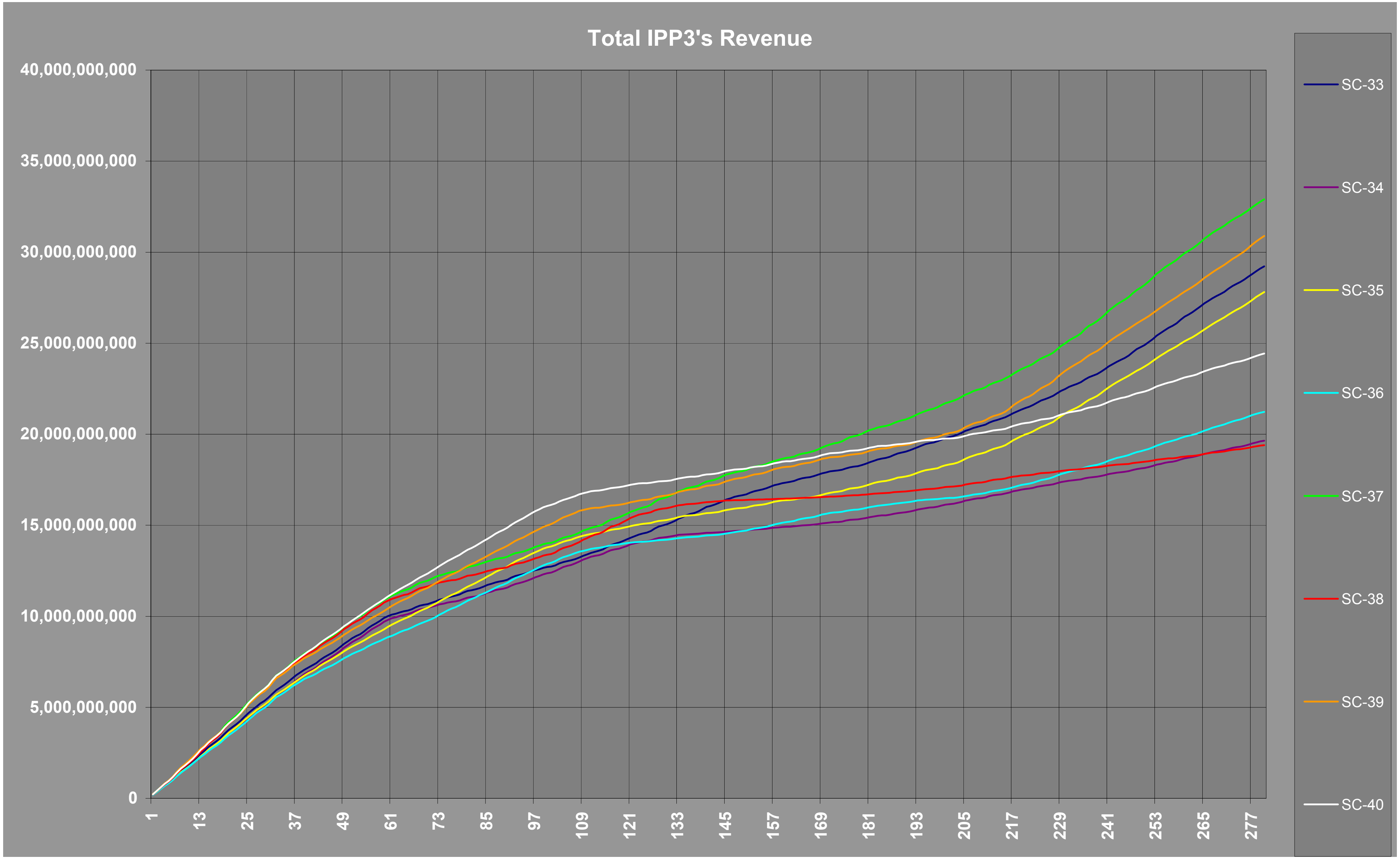

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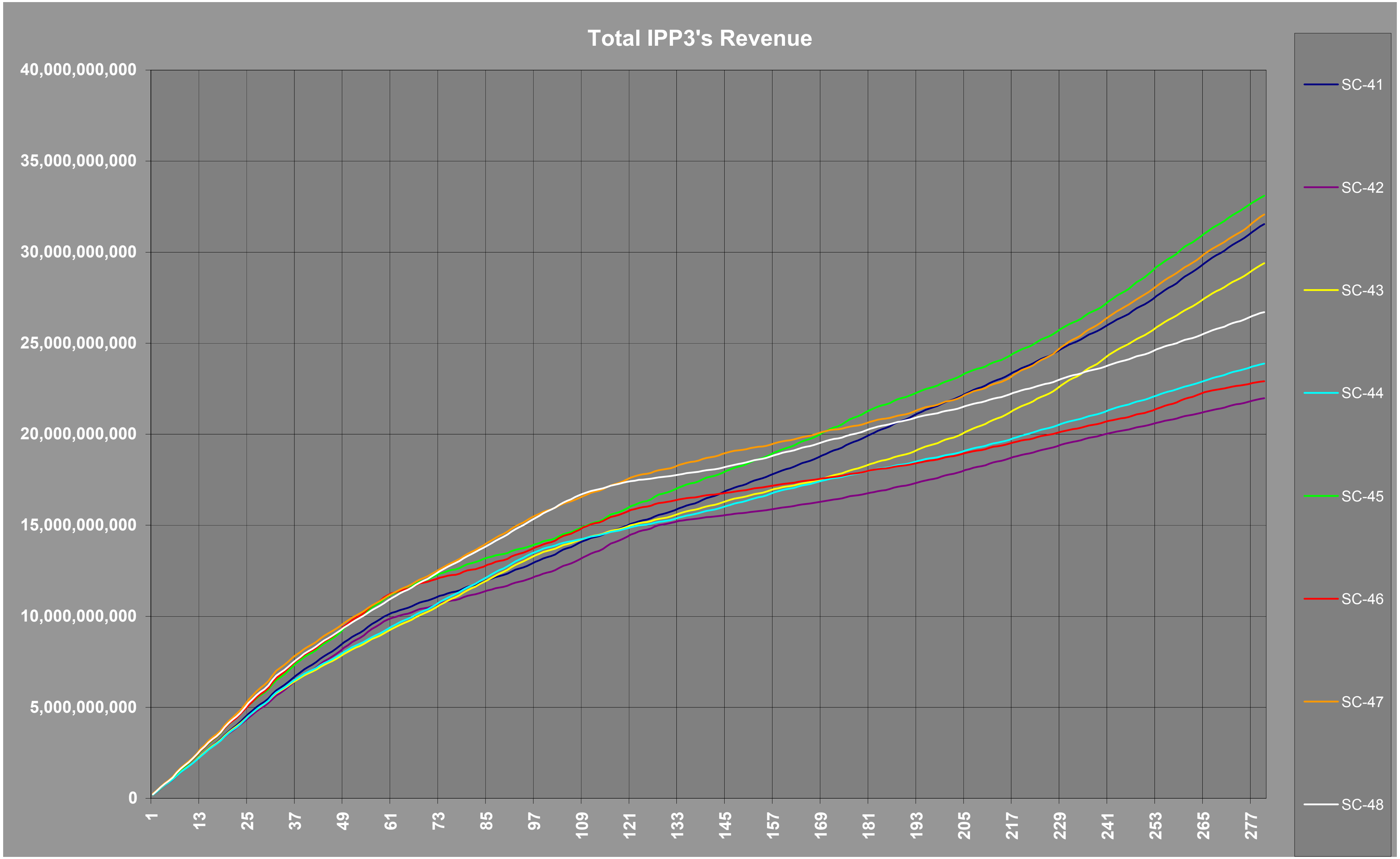

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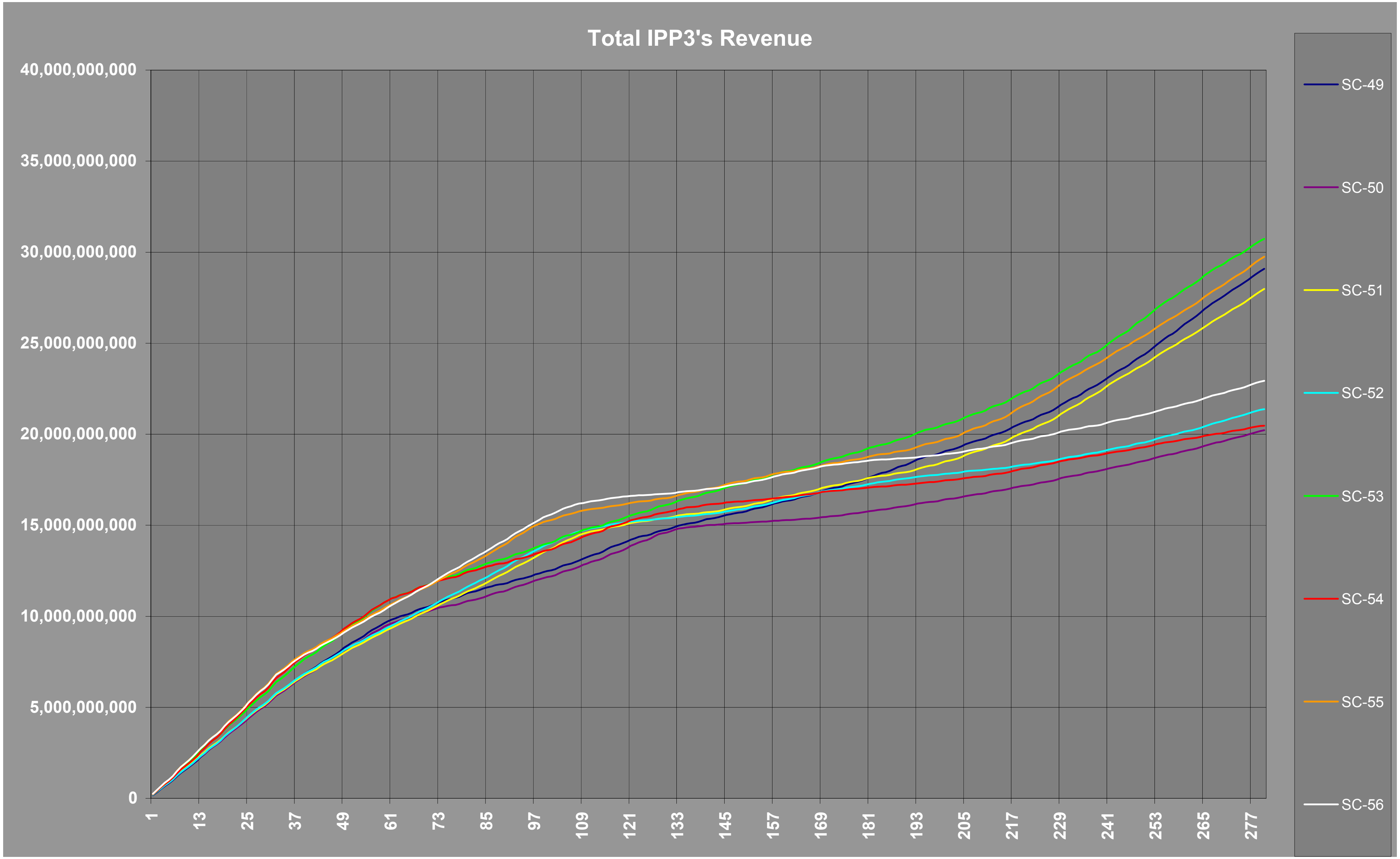

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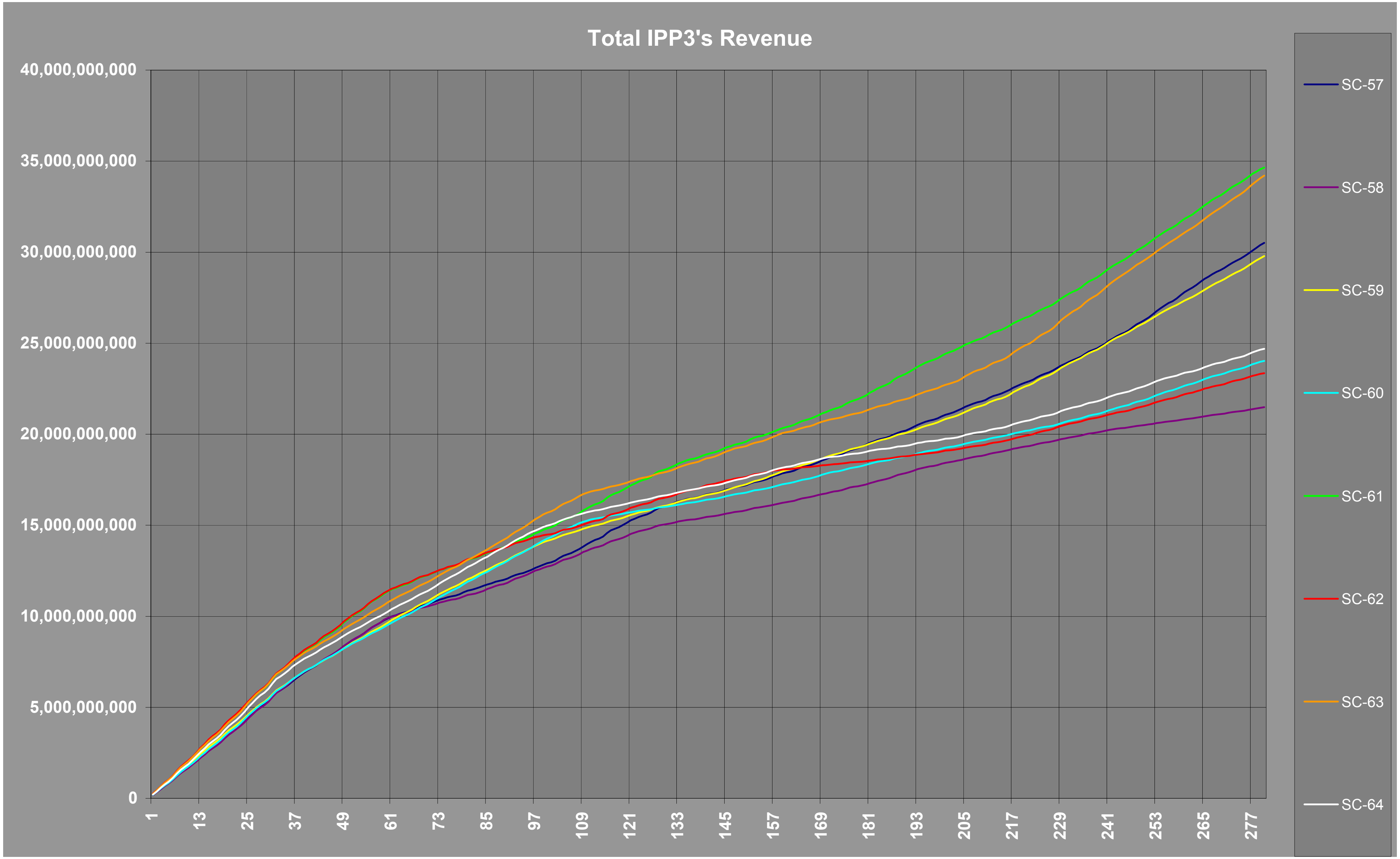

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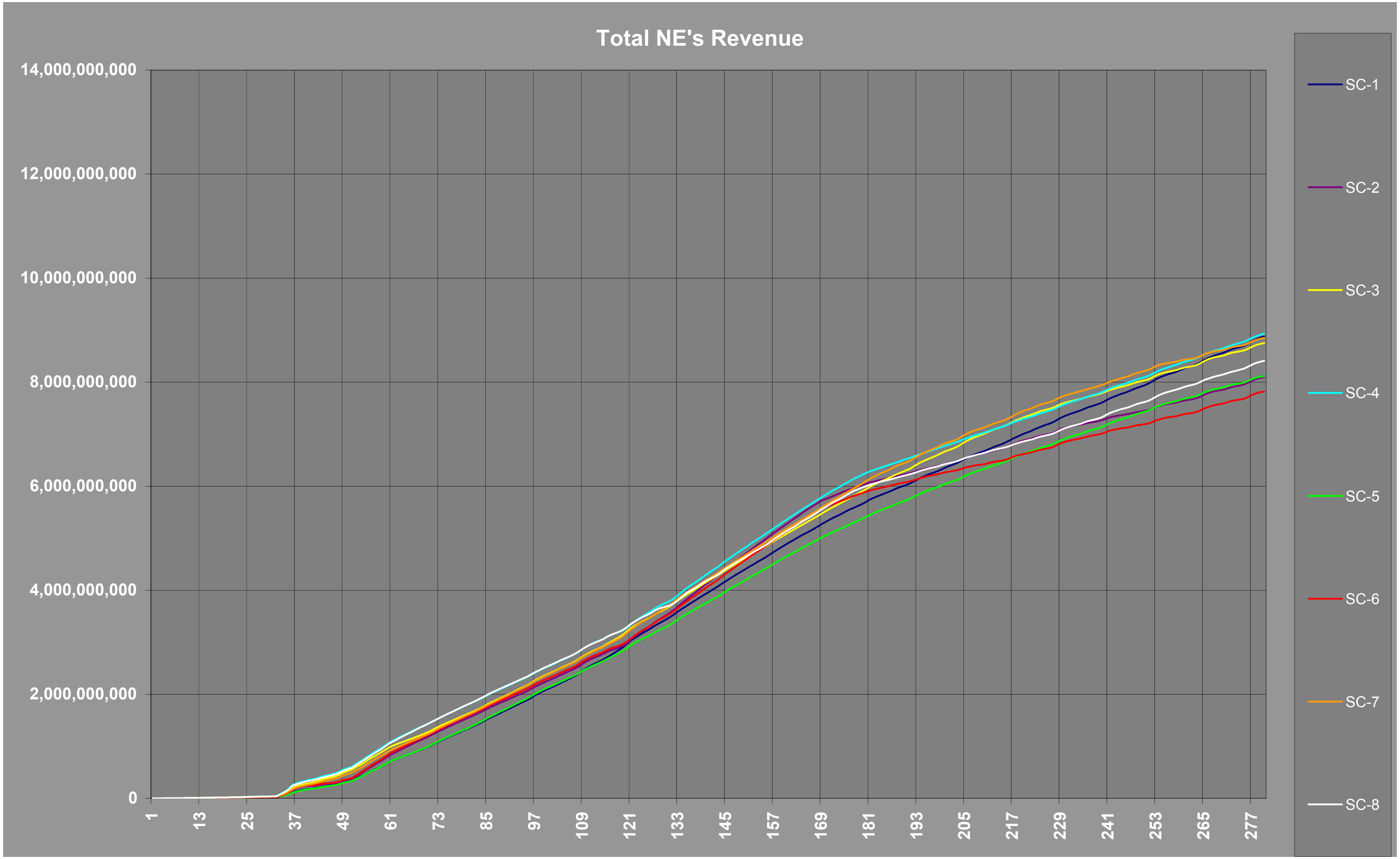

Total NE's Revenue
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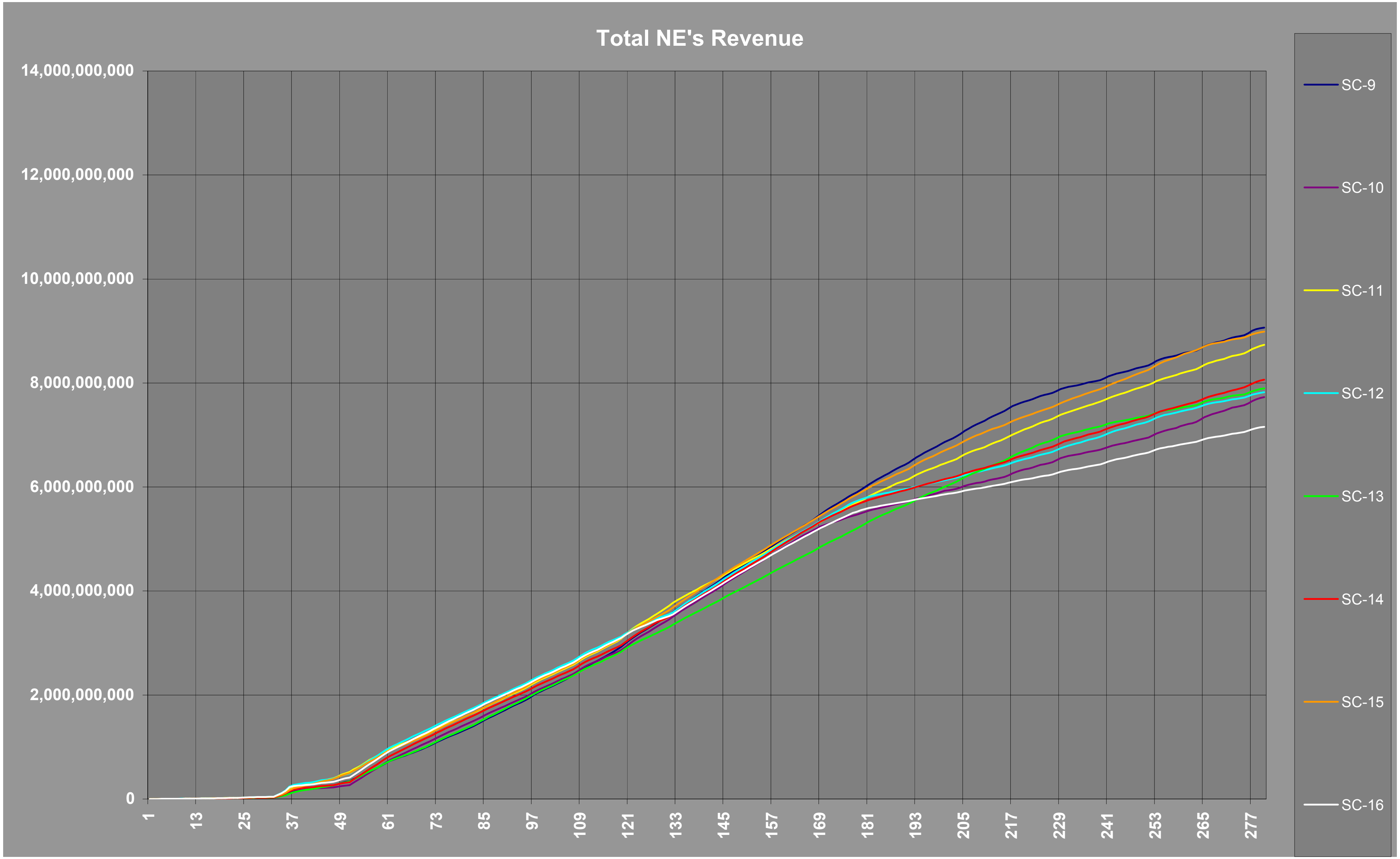
Total NE's Revenue
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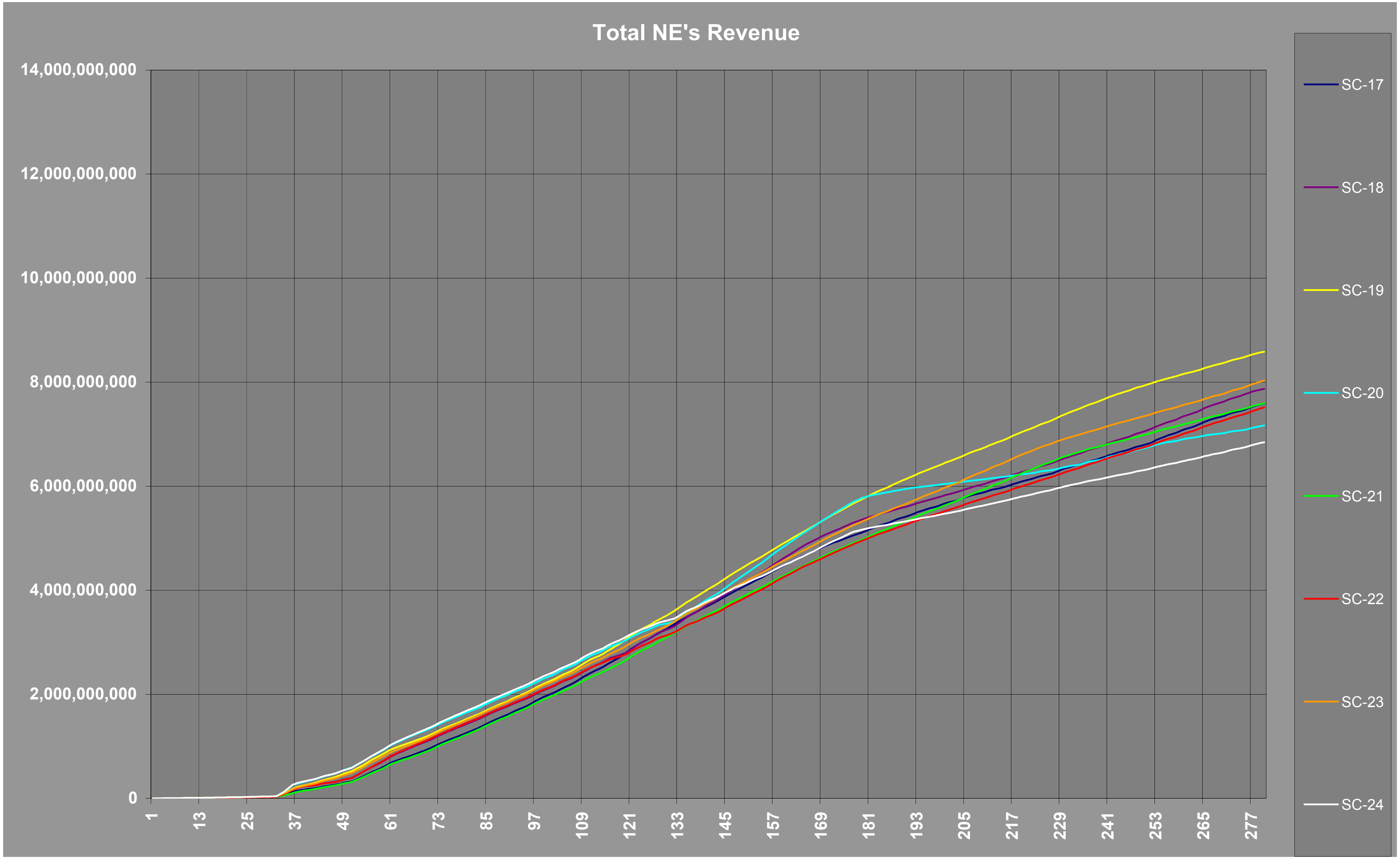
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Total NE's Revenue
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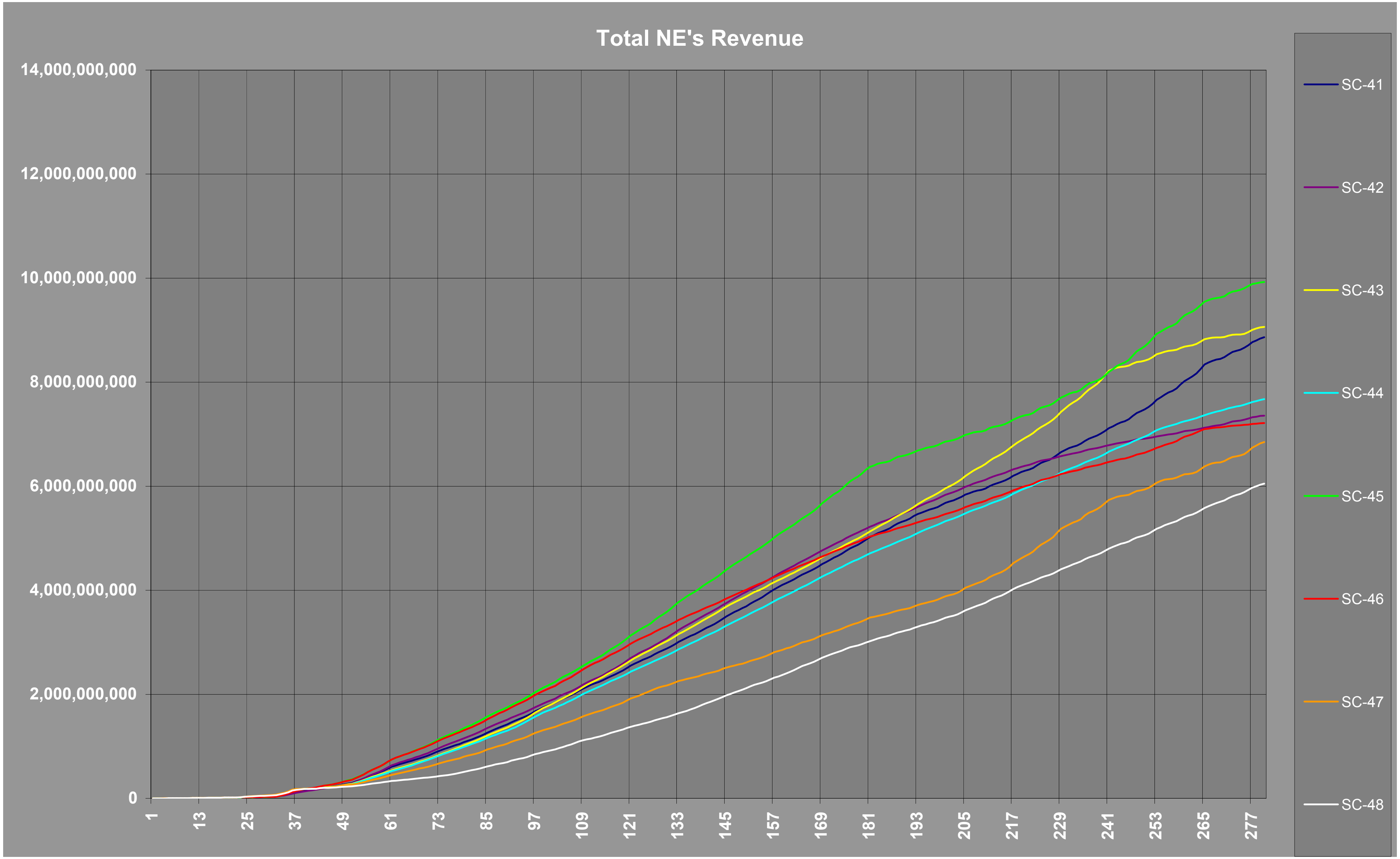
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Total NE's Revenue
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Total NE's Revenue
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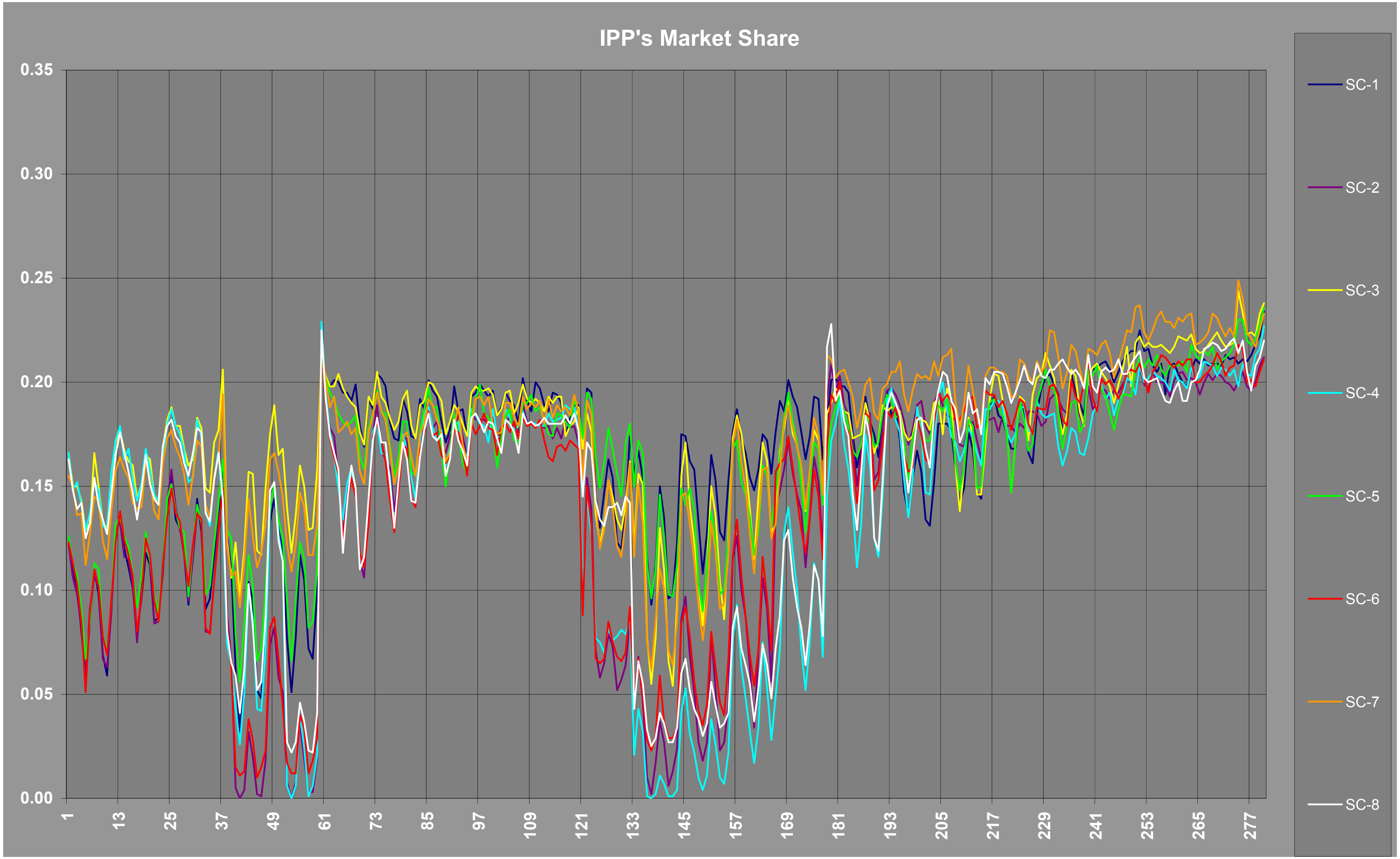

IPP's Market Share
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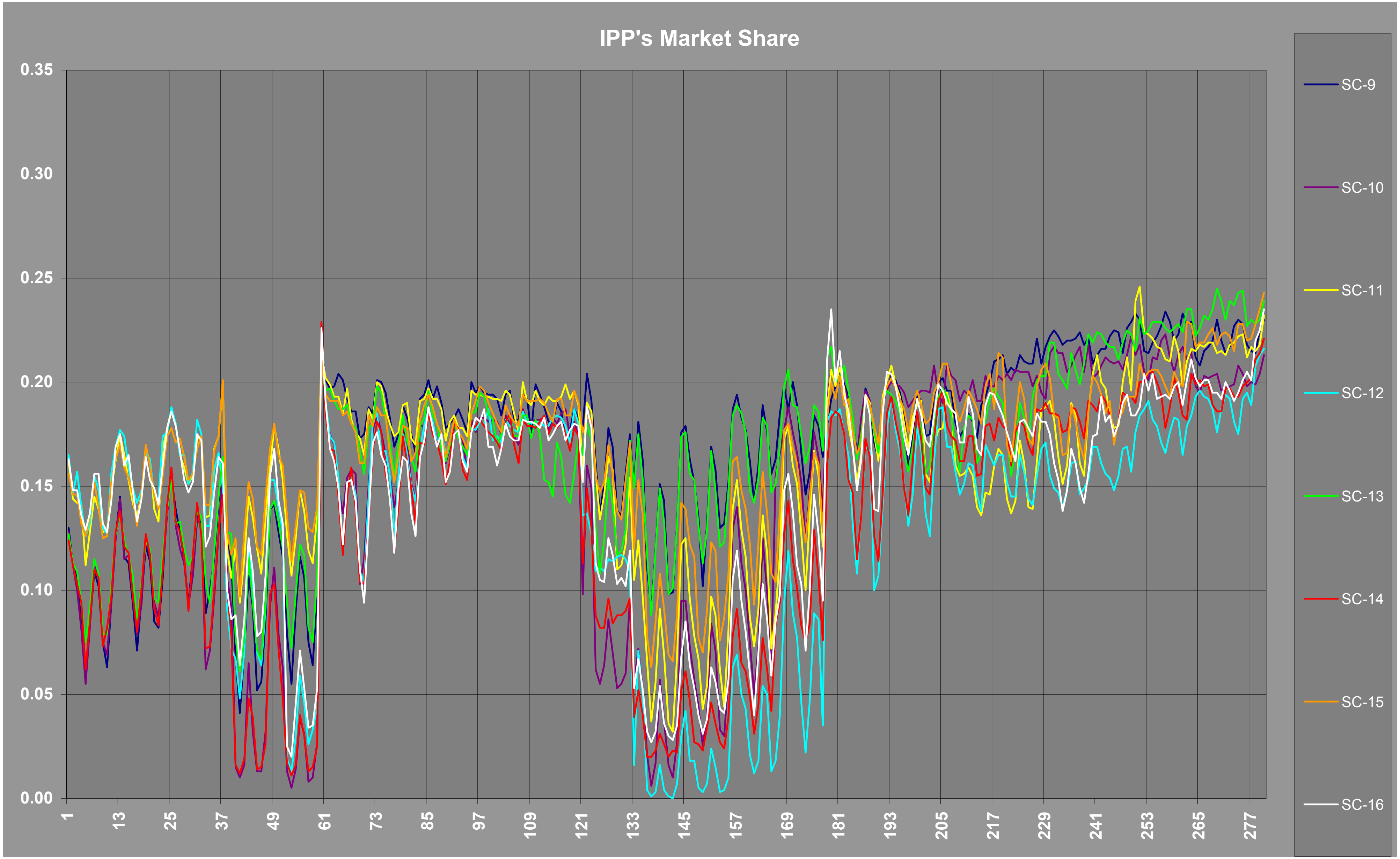
IPP's Market Share
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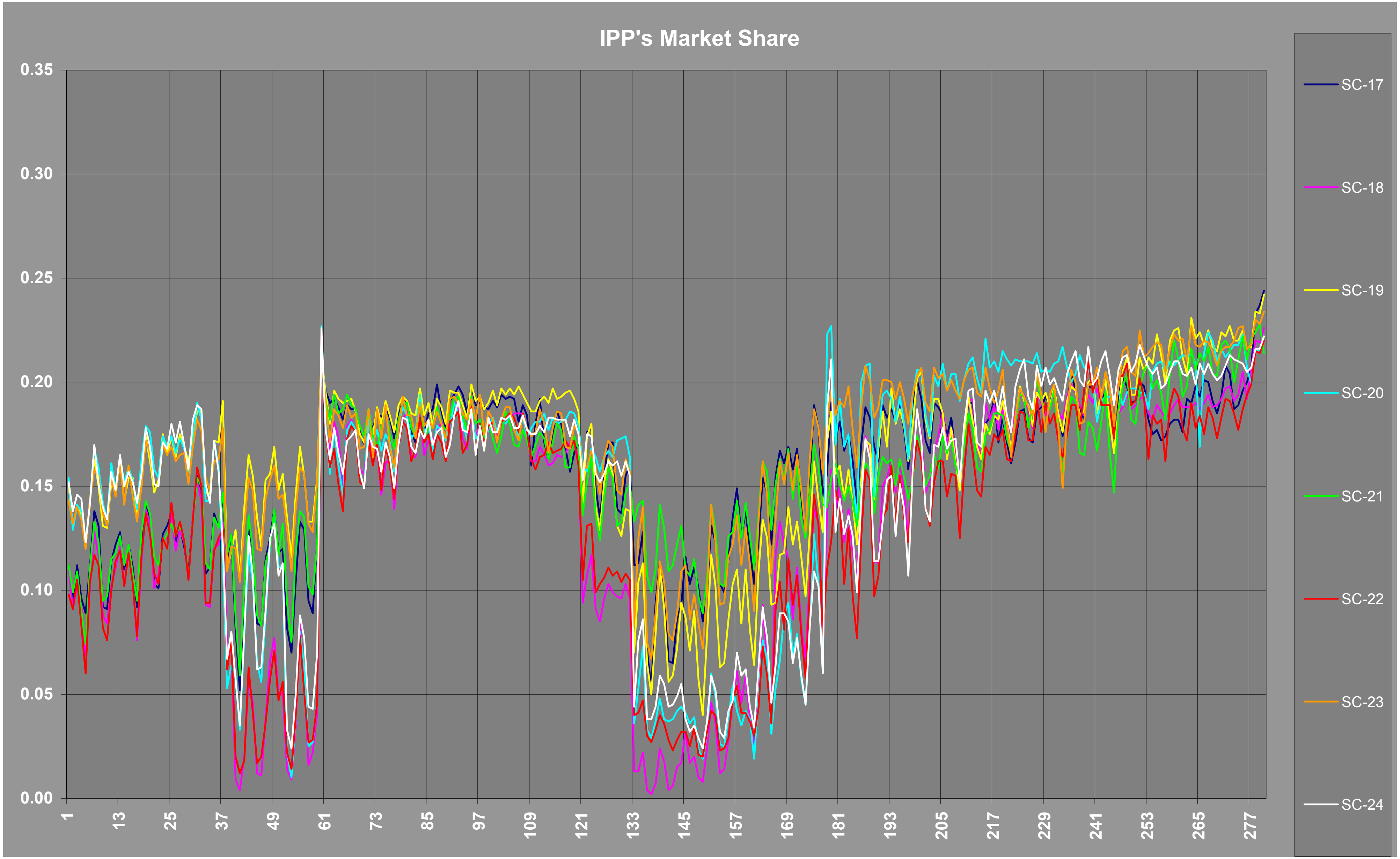
IPP's Market Share
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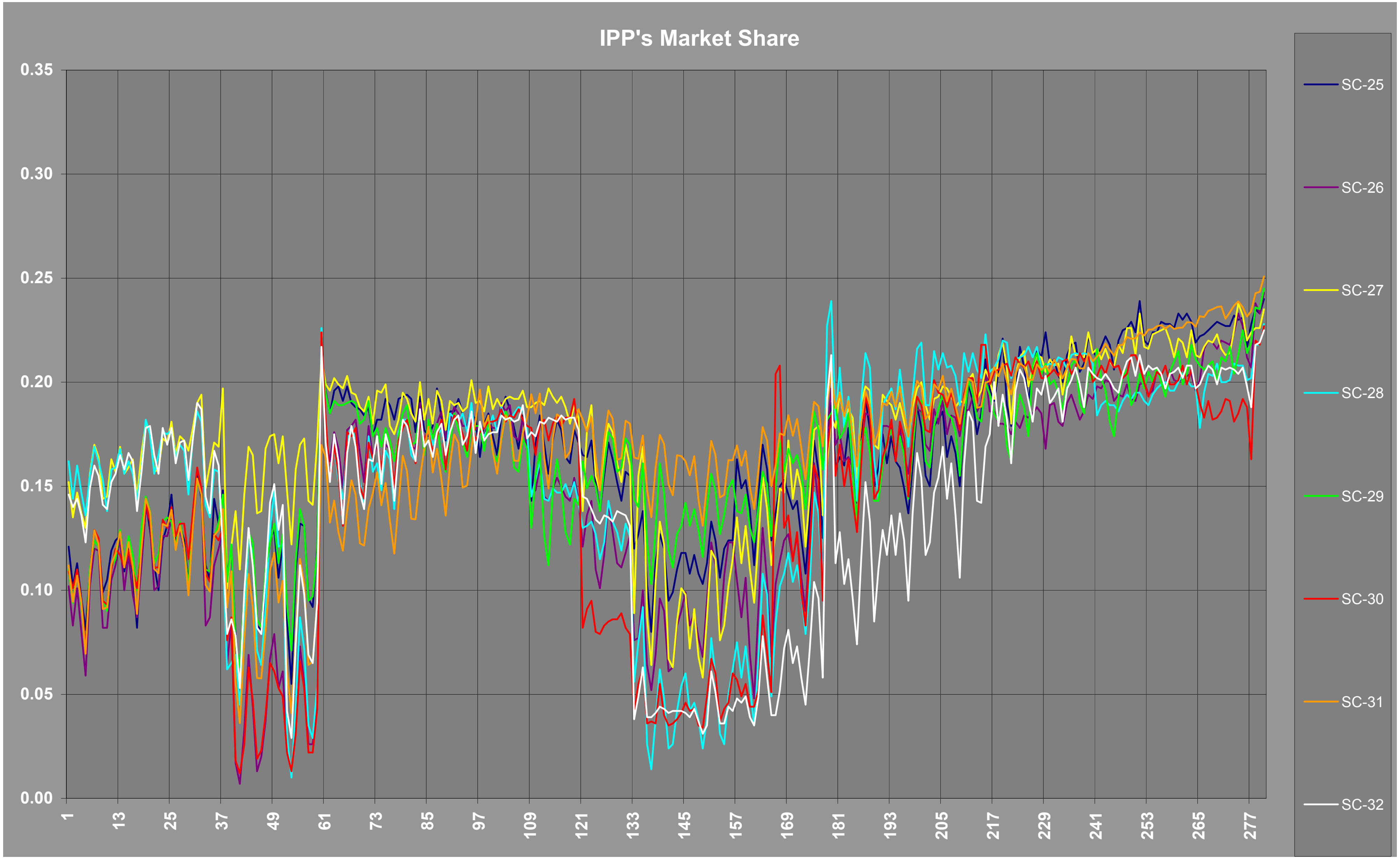
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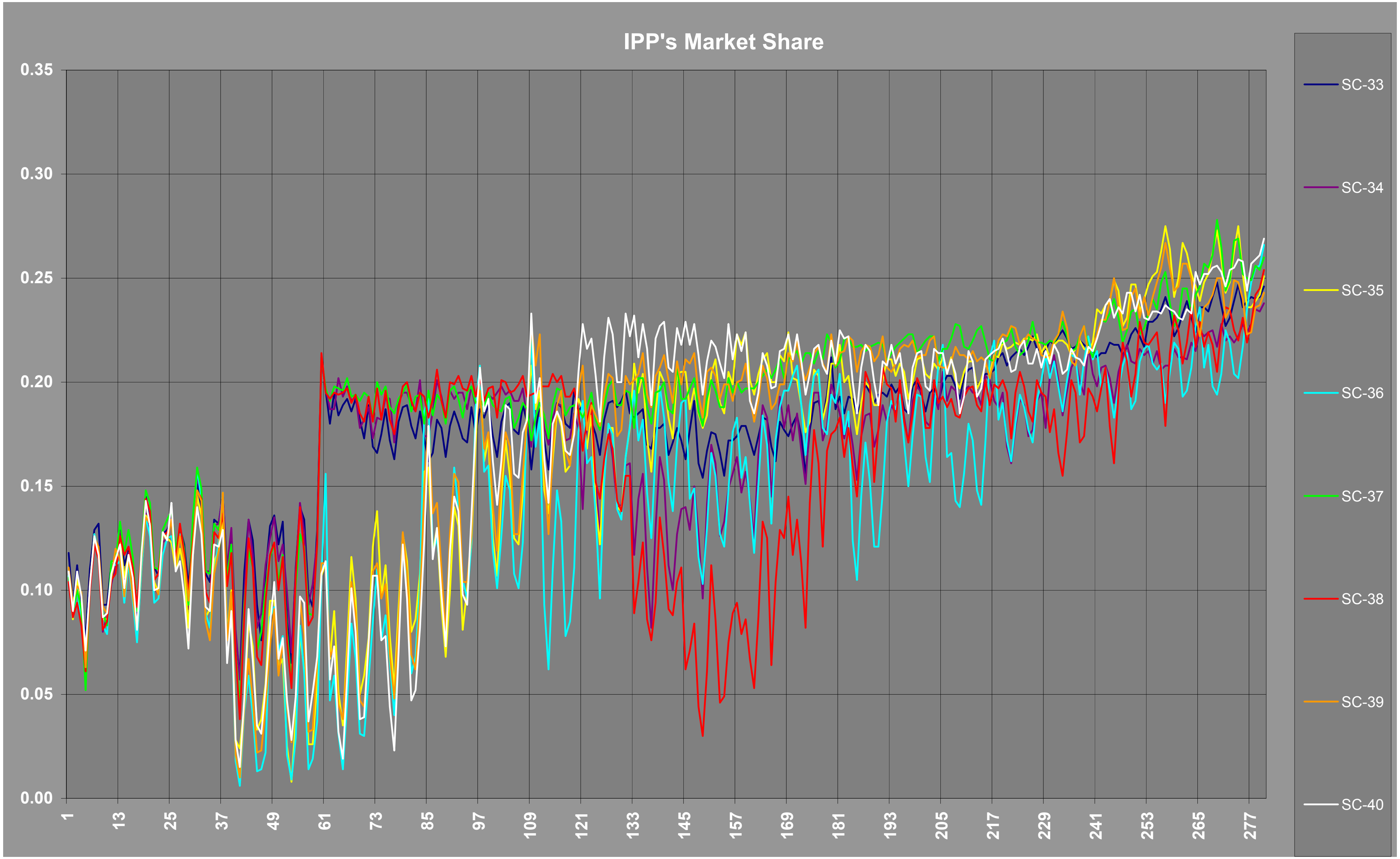
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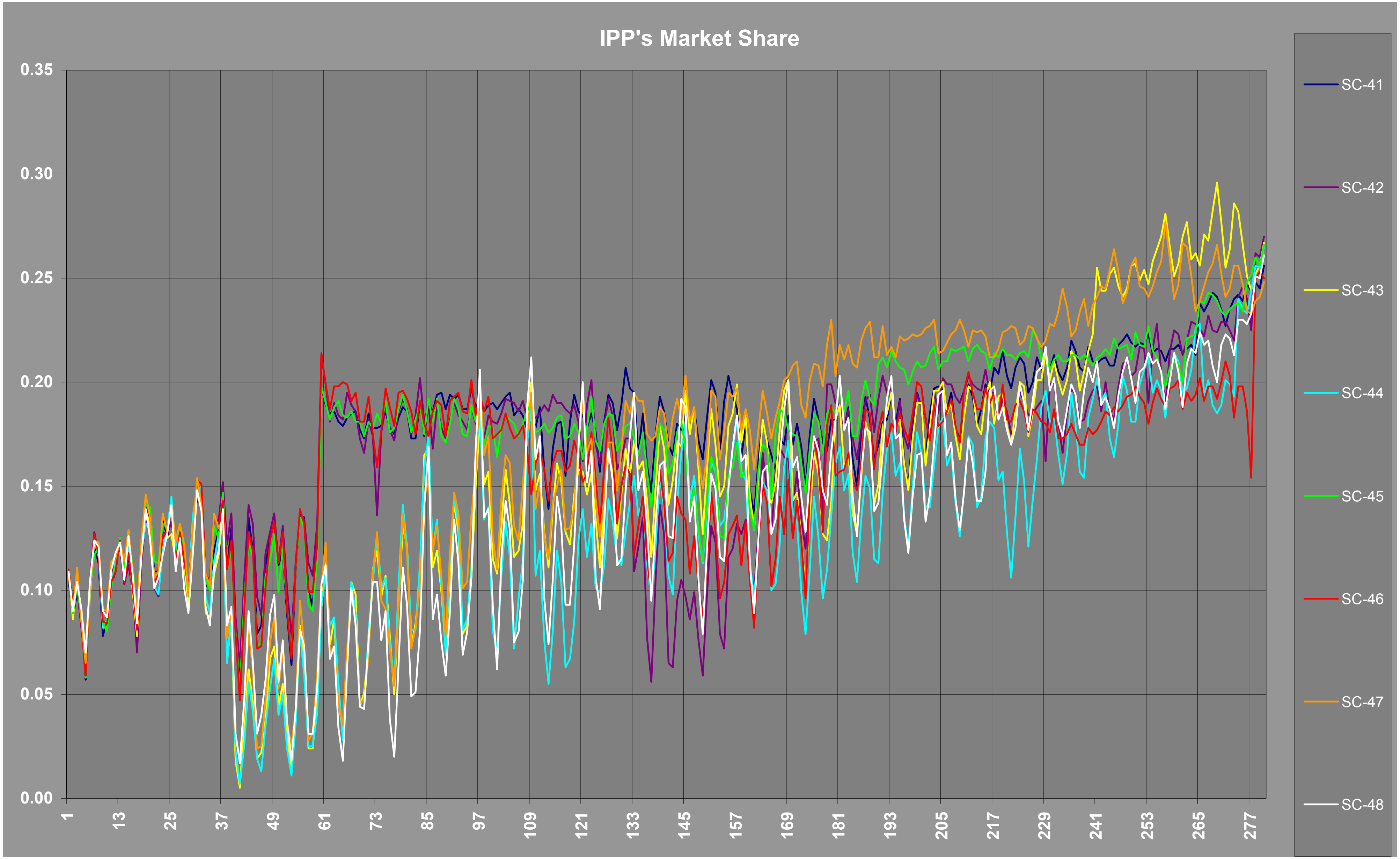
IPP's Market Share
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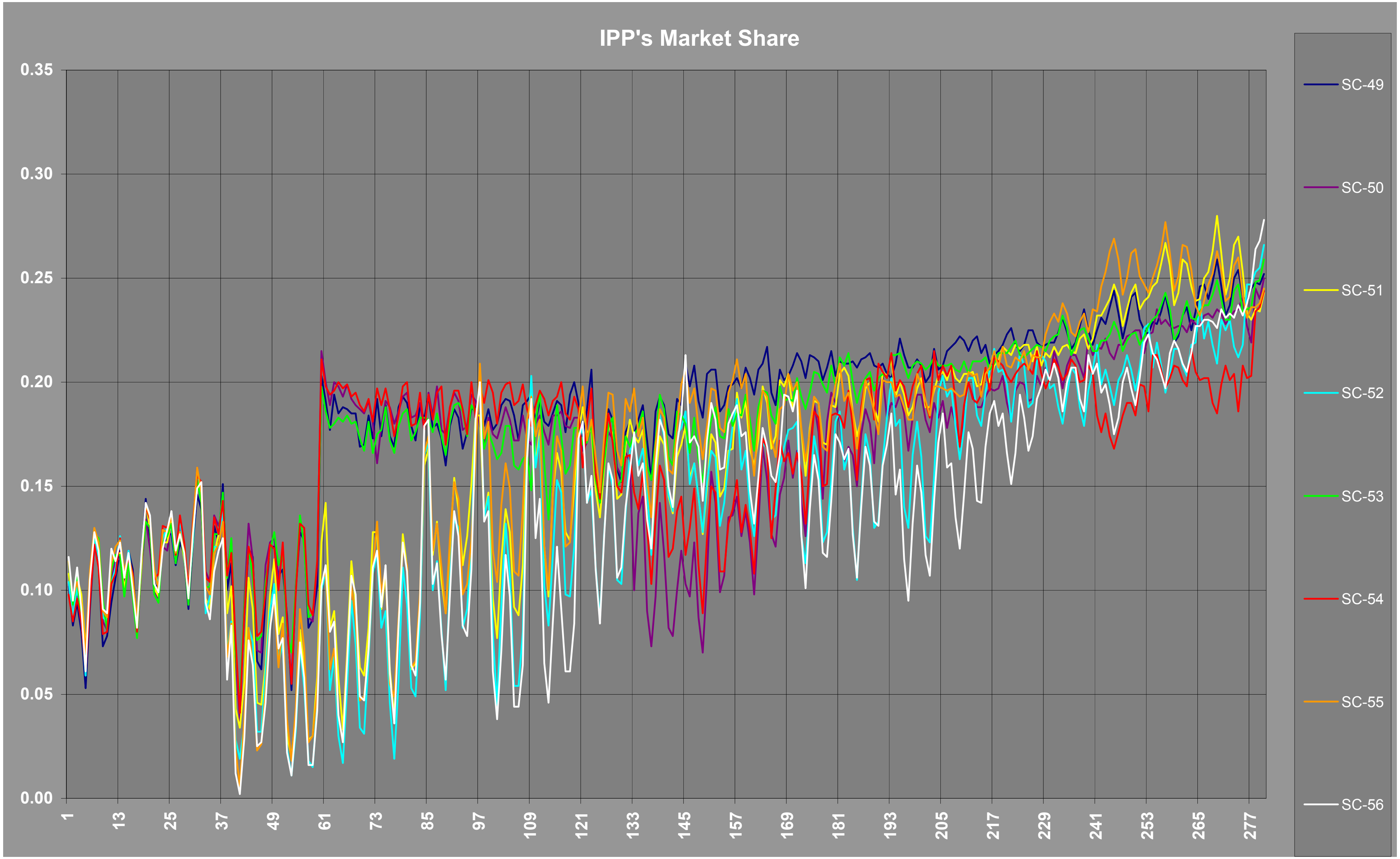

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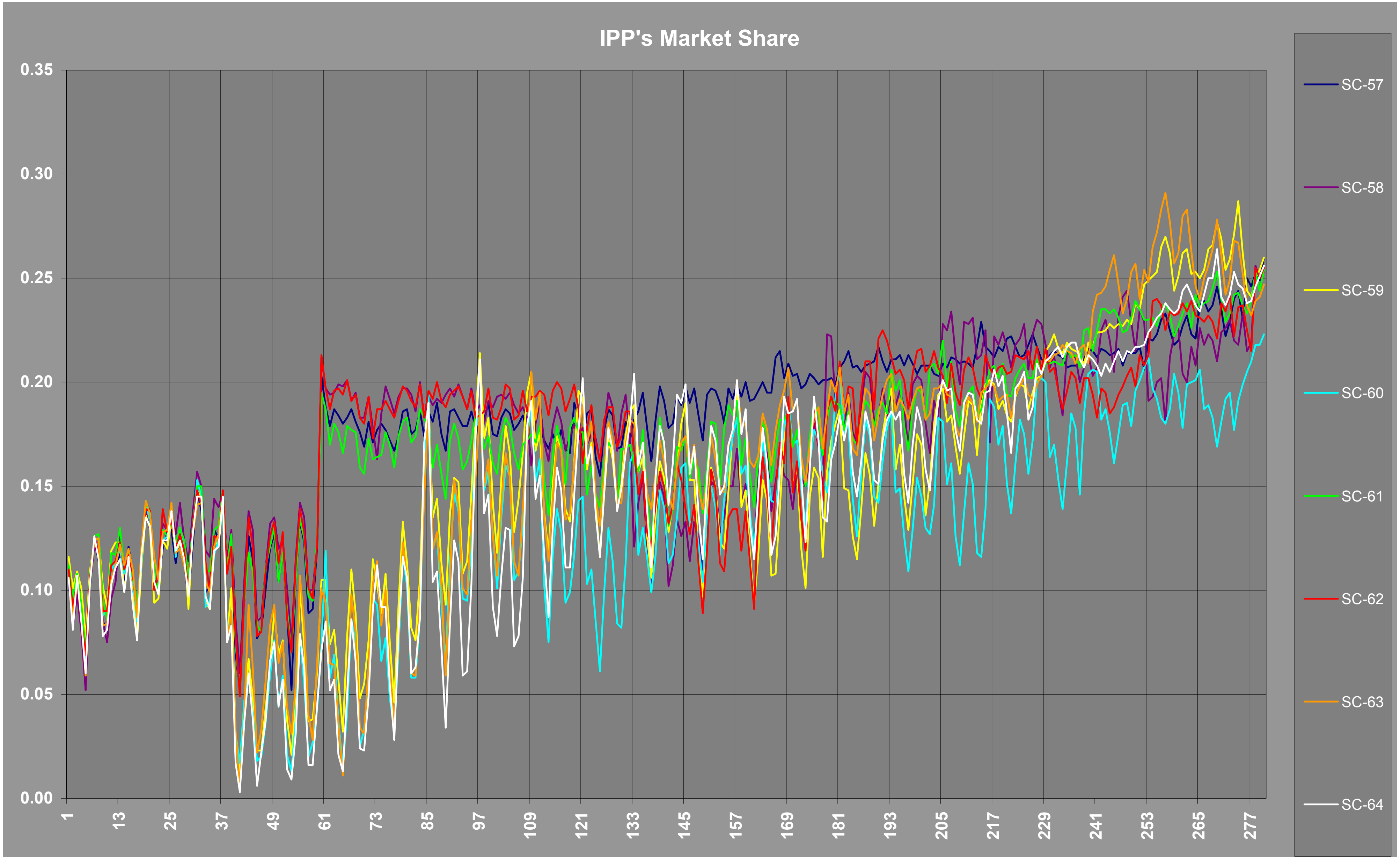

IPP's Market Share
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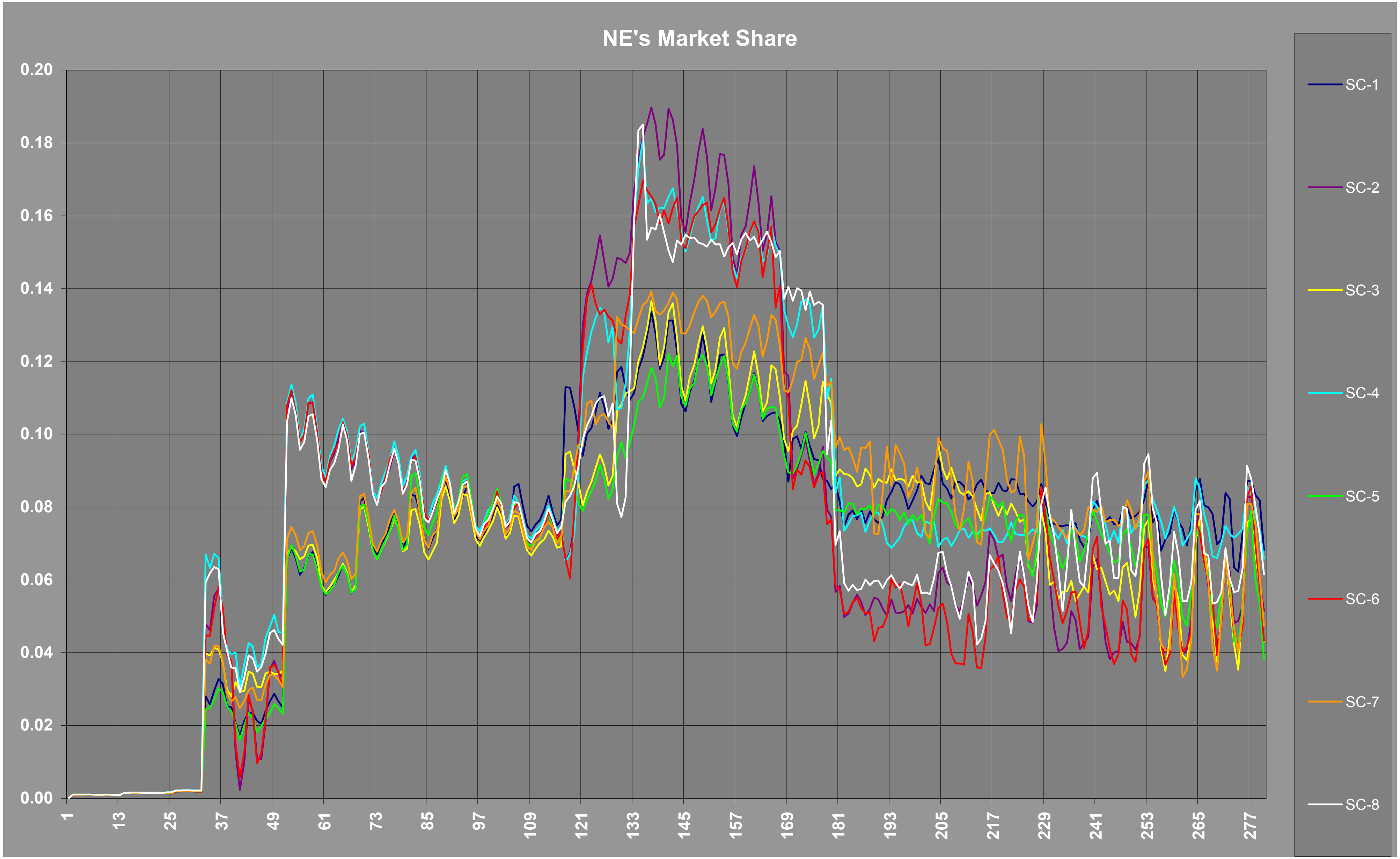
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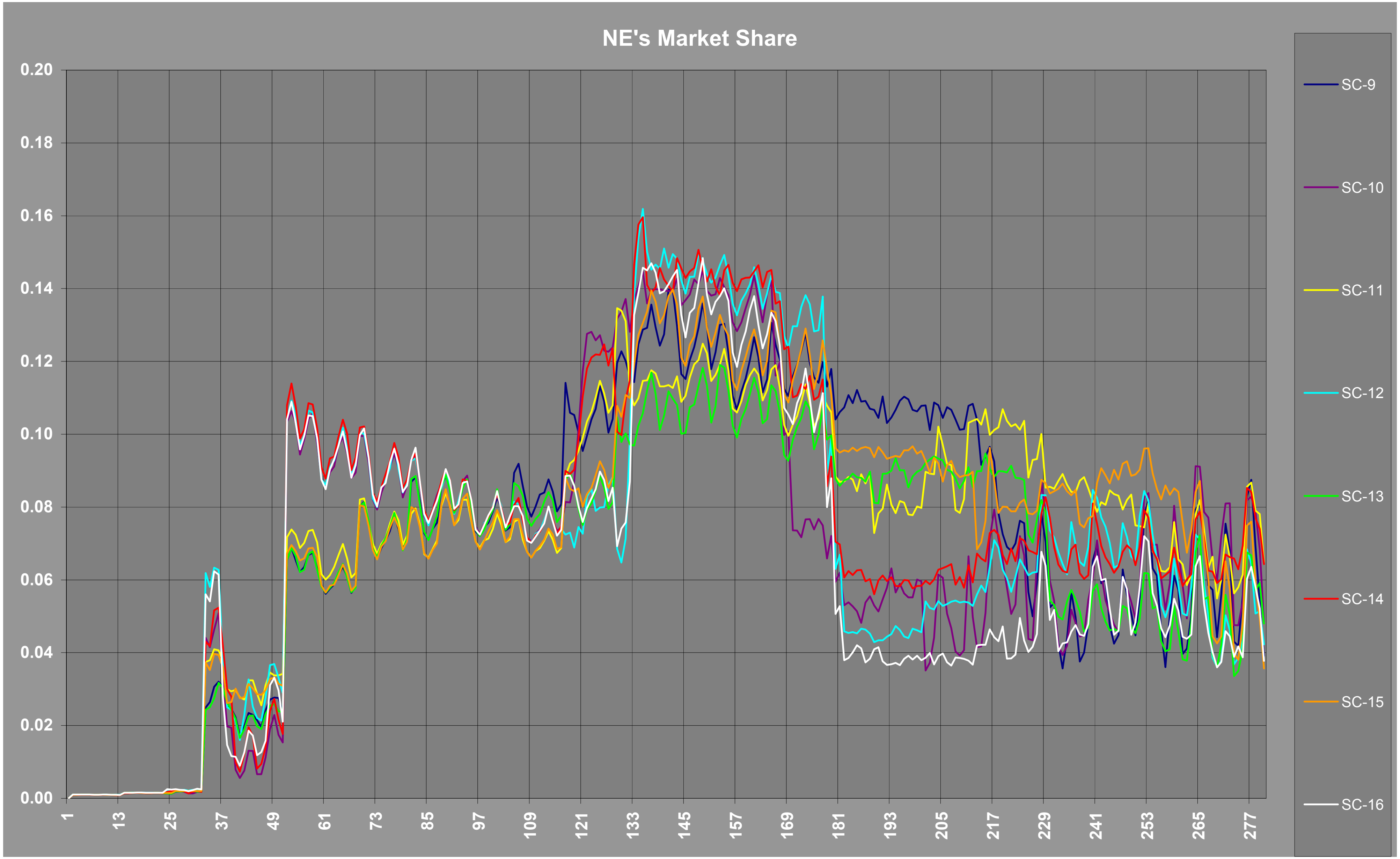
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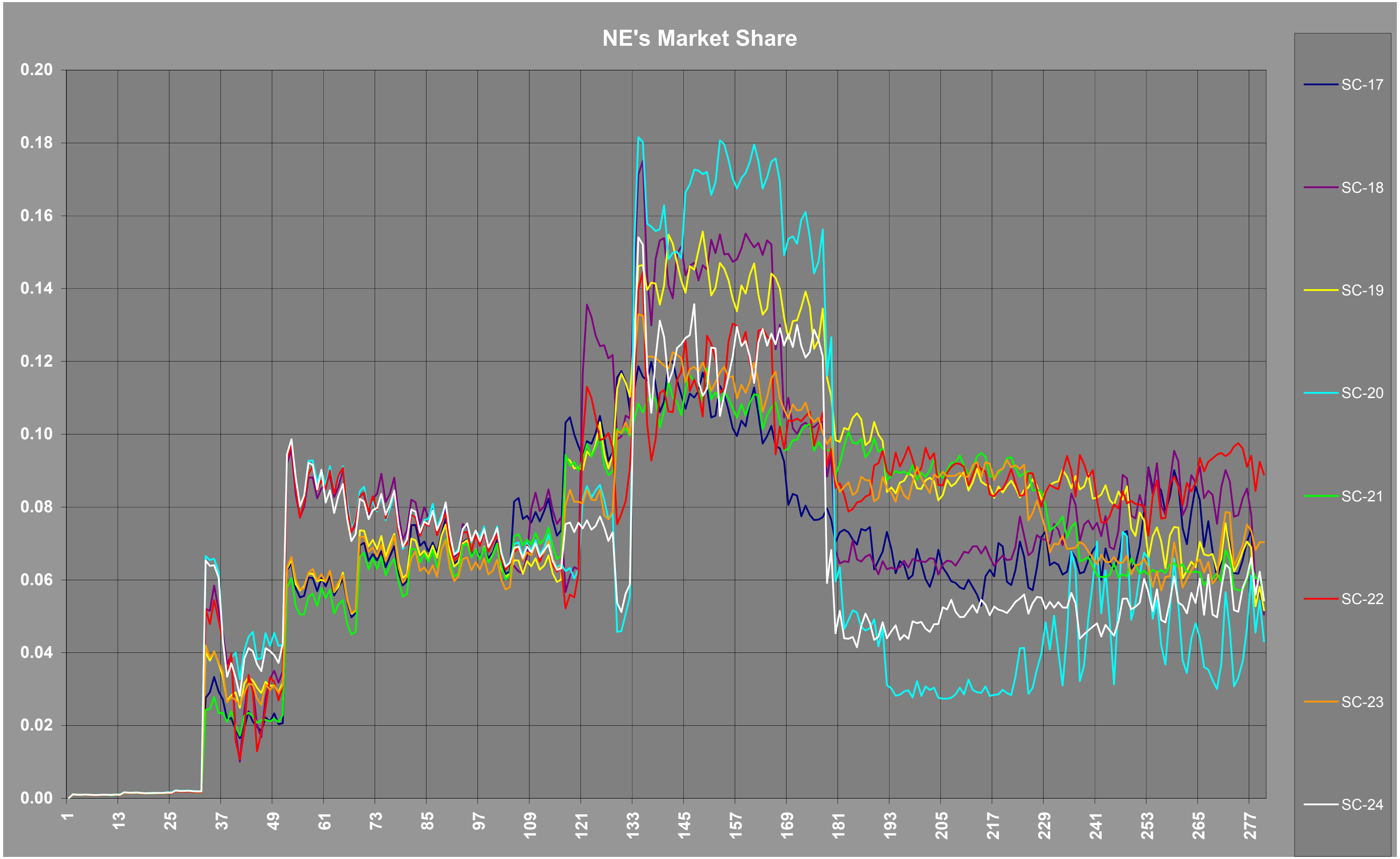
NE's Market Share
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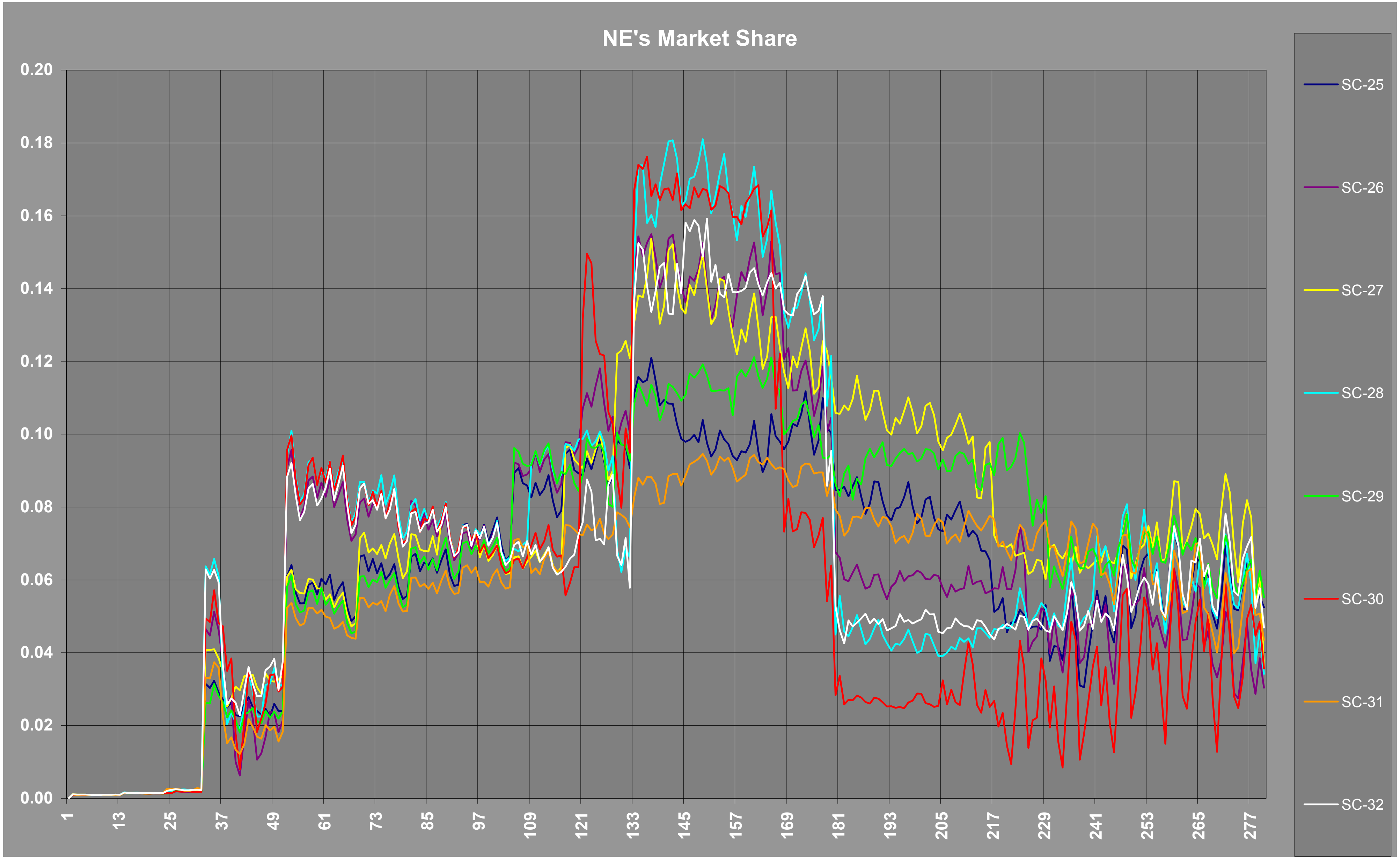

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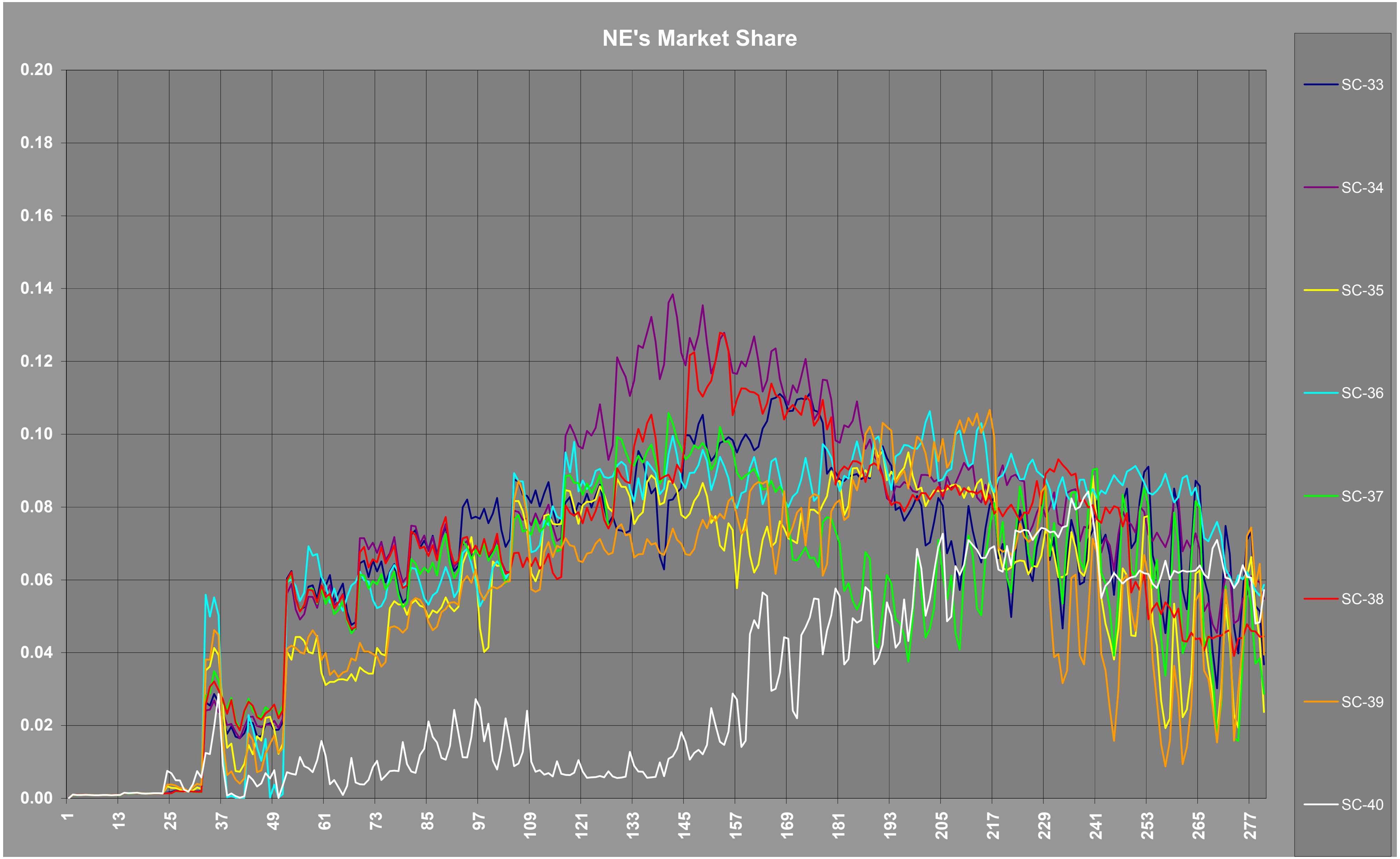

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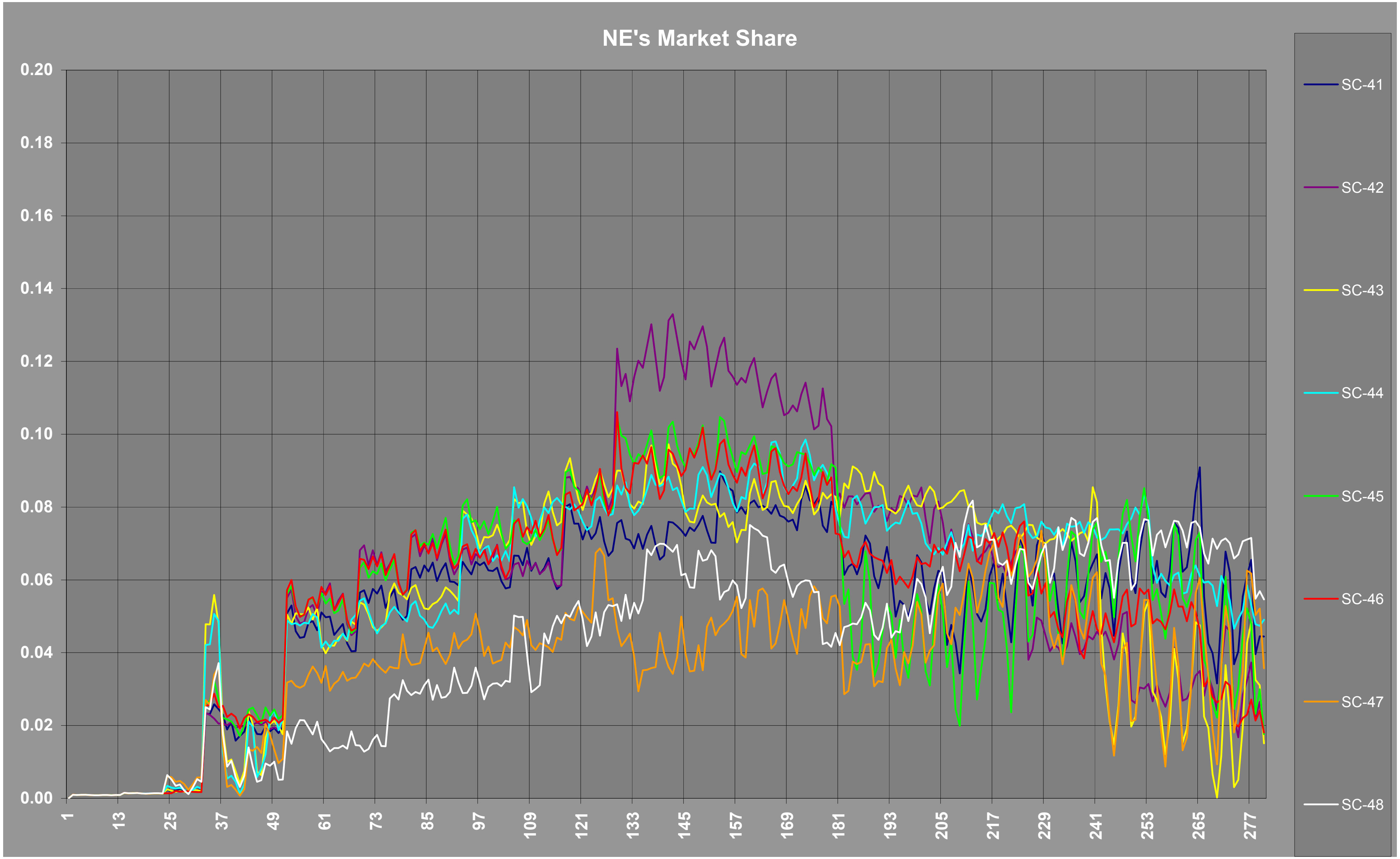

NE's Market Share
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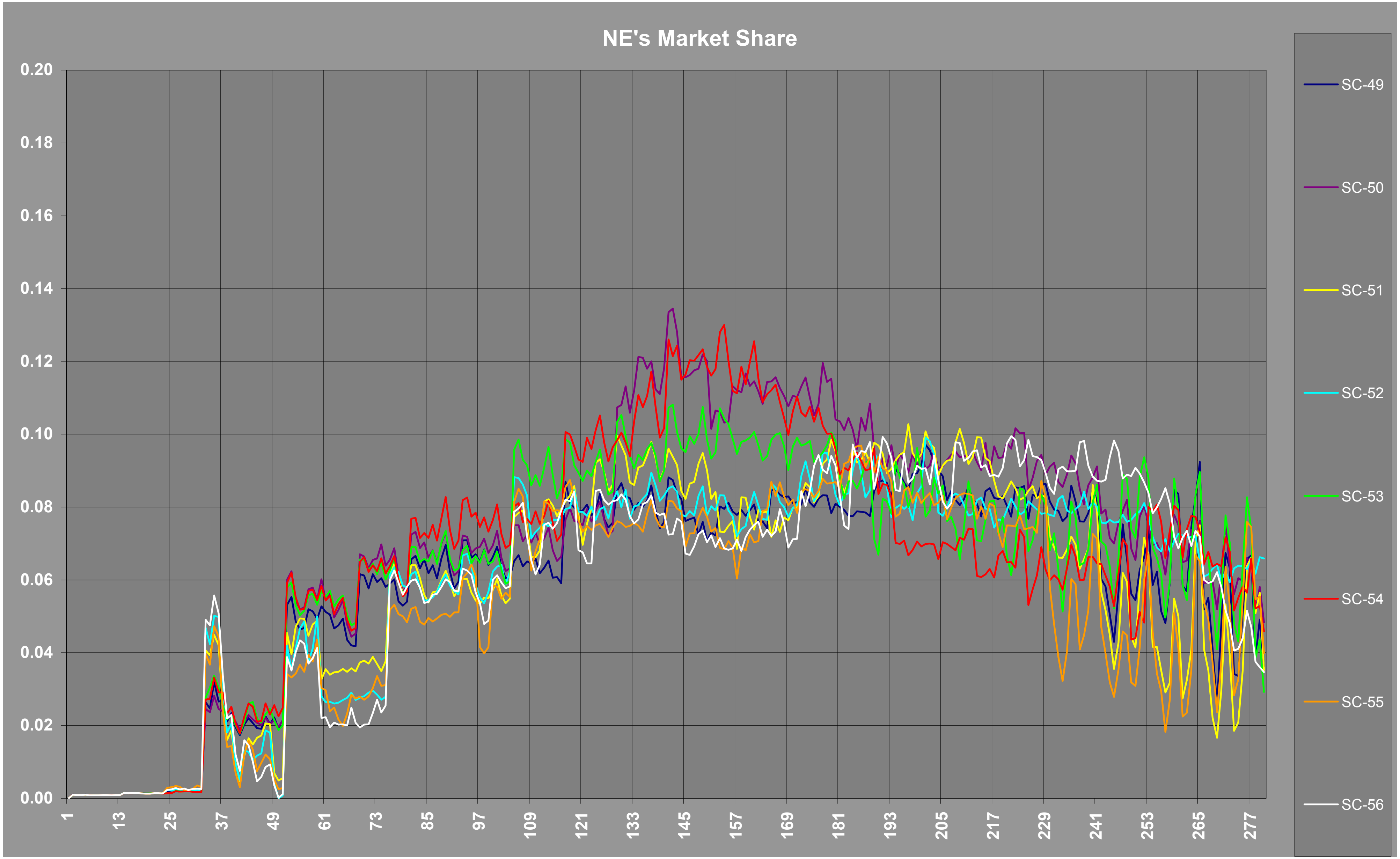

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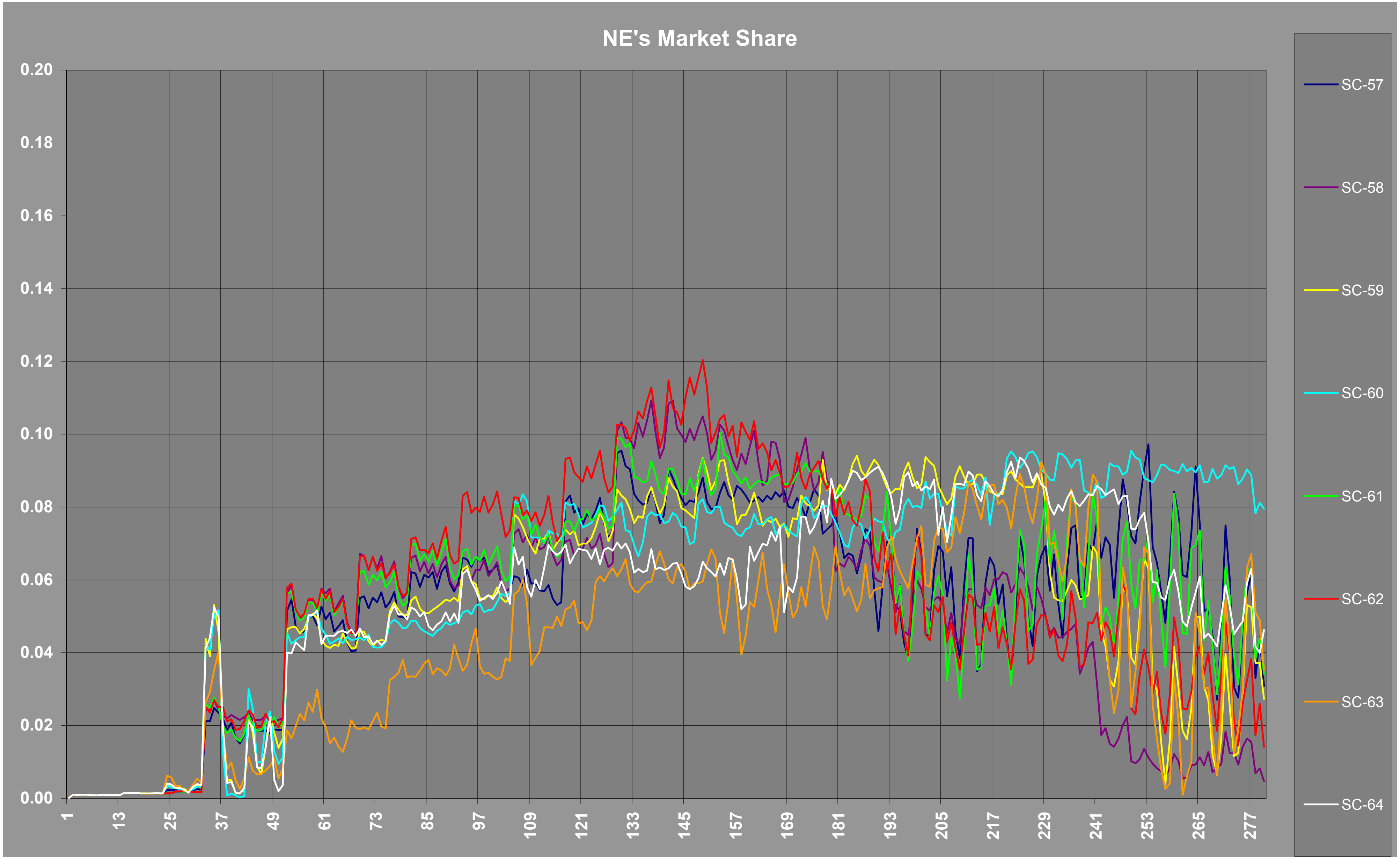

NE's Market Share
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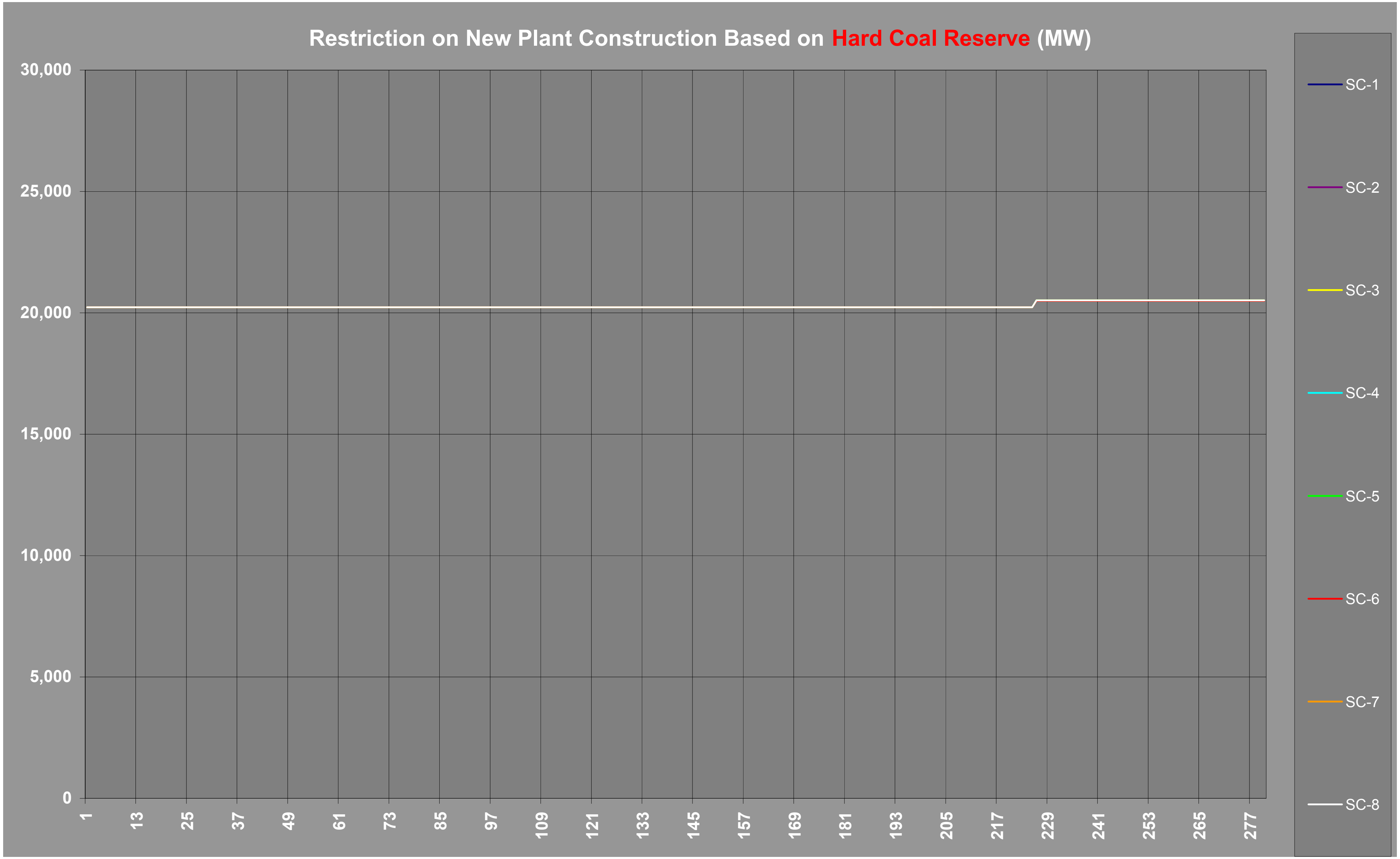
Restriction on New Plant Construction Based on Hard Coal Reserve (MW)
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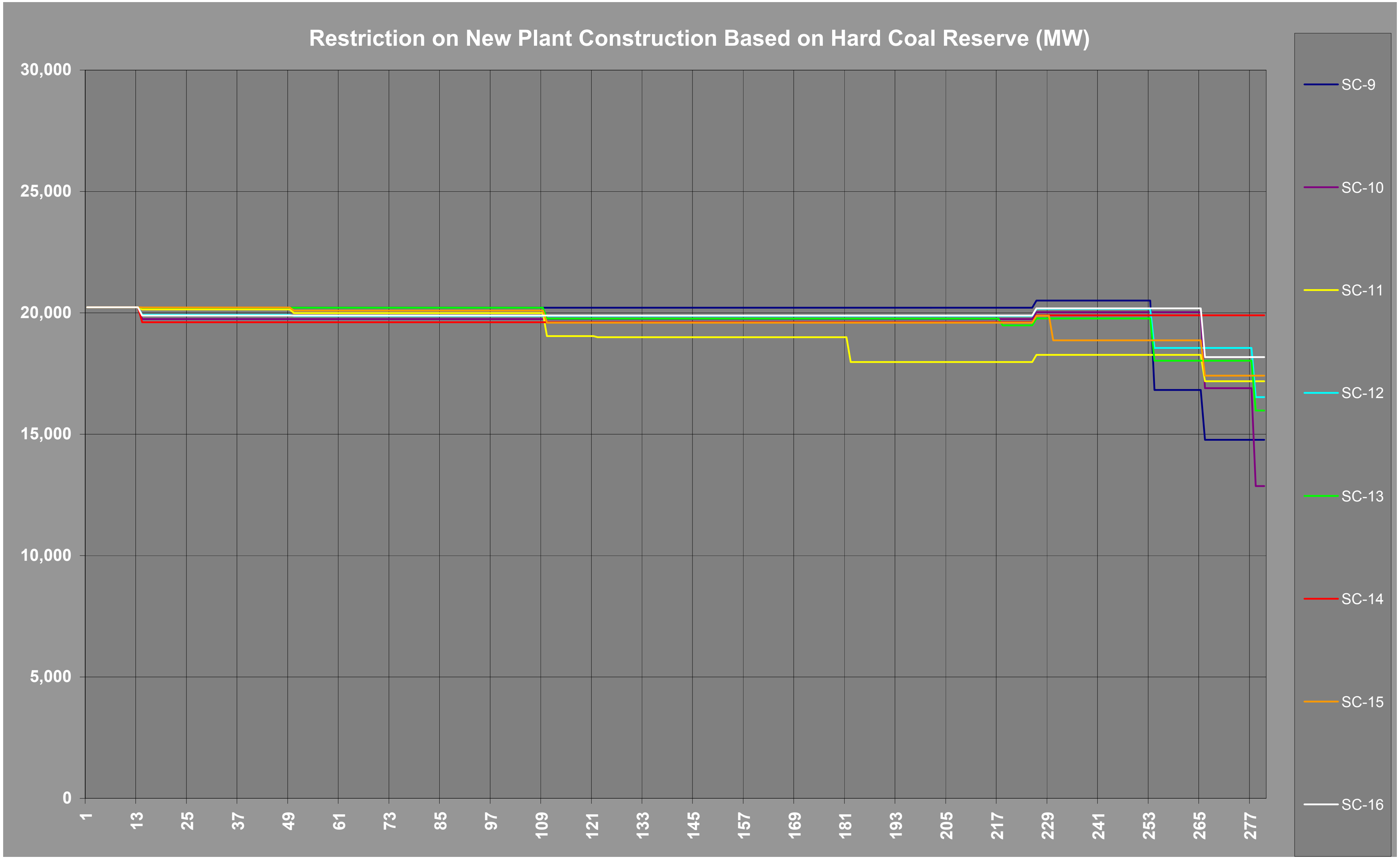
Restriction on New Plant Construction Based on Hard Coal Reserve (MW)
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20,000
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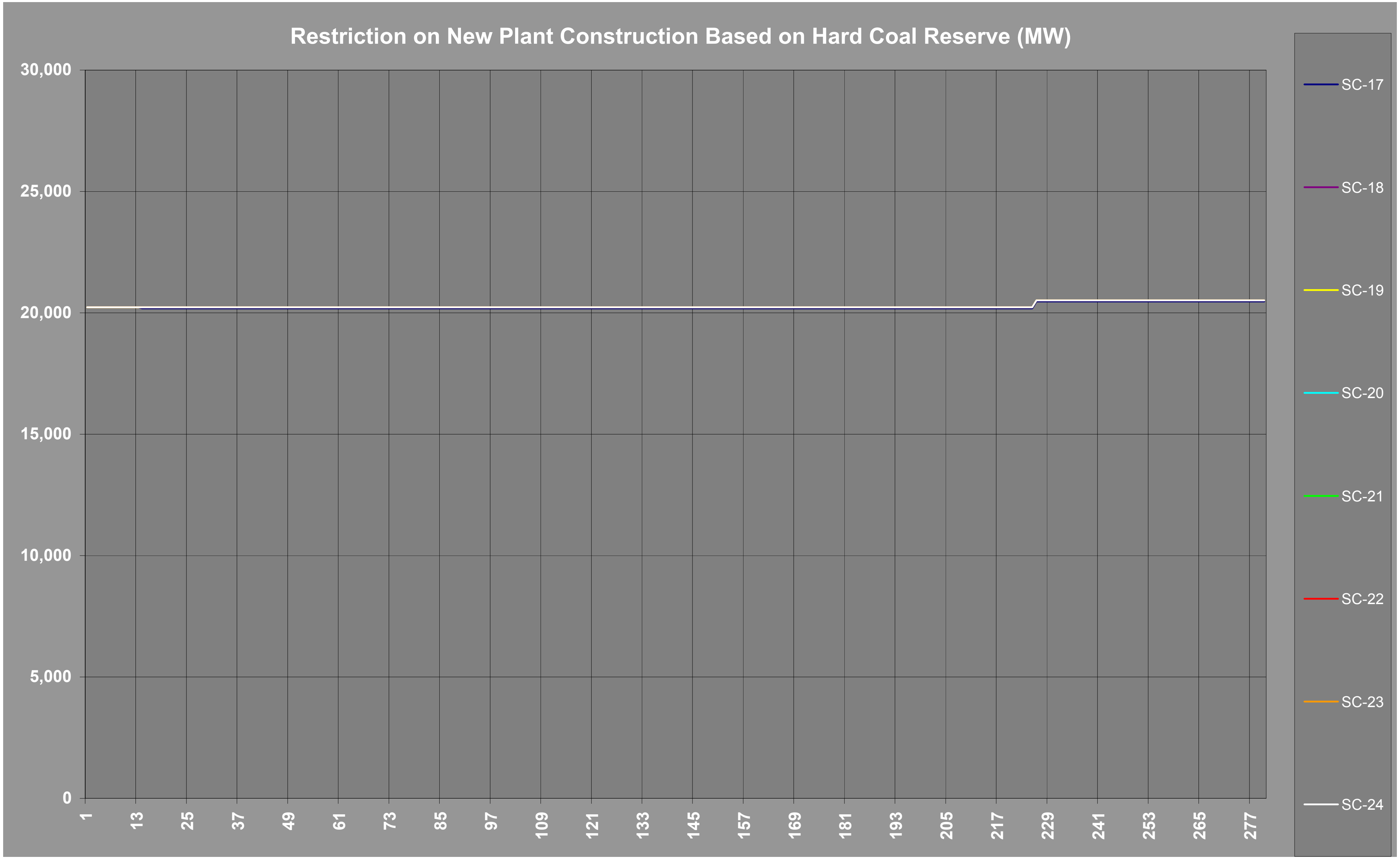

Restriction on New Plant Construction Based on Hard Coal Reserve (MW)
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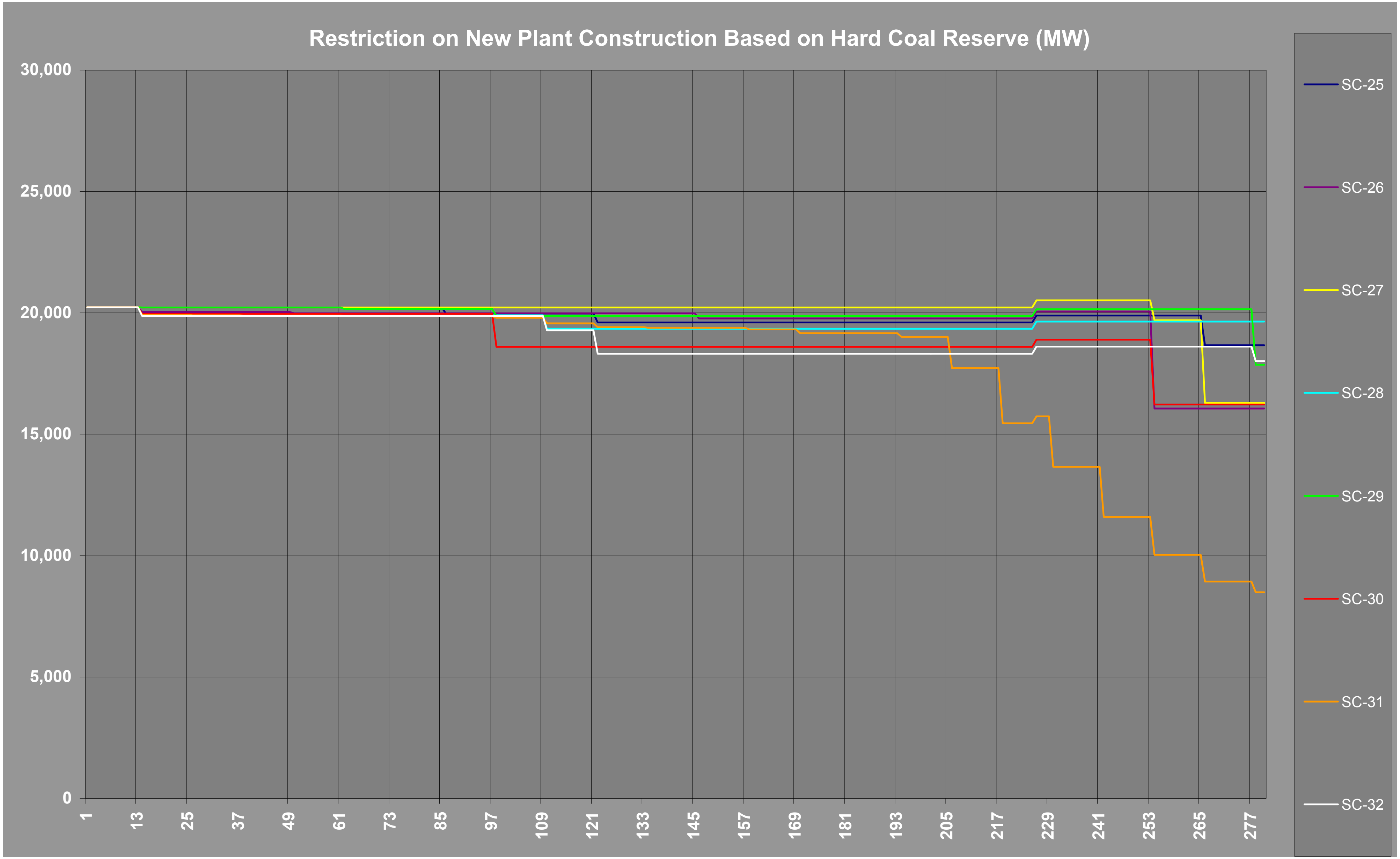
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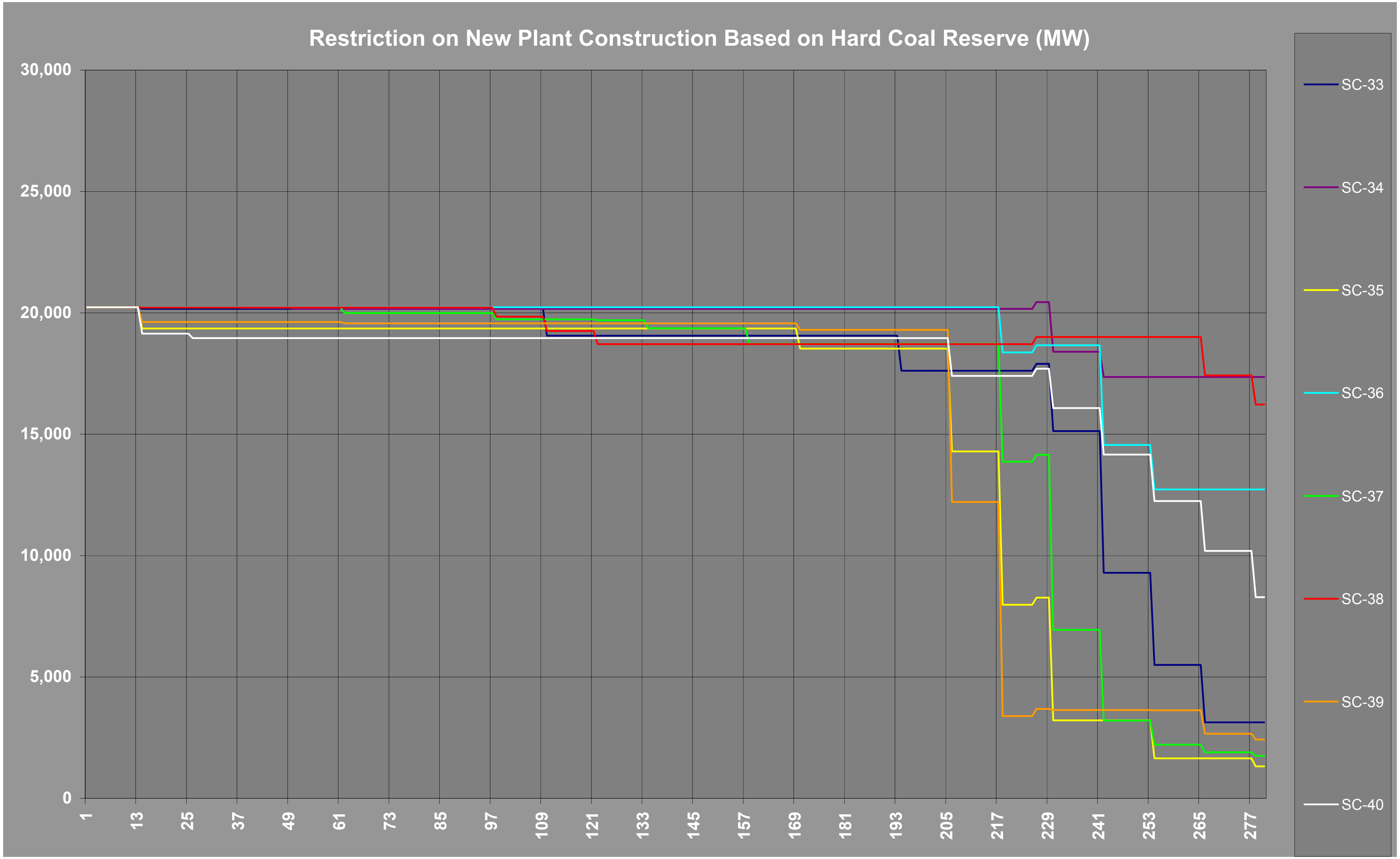
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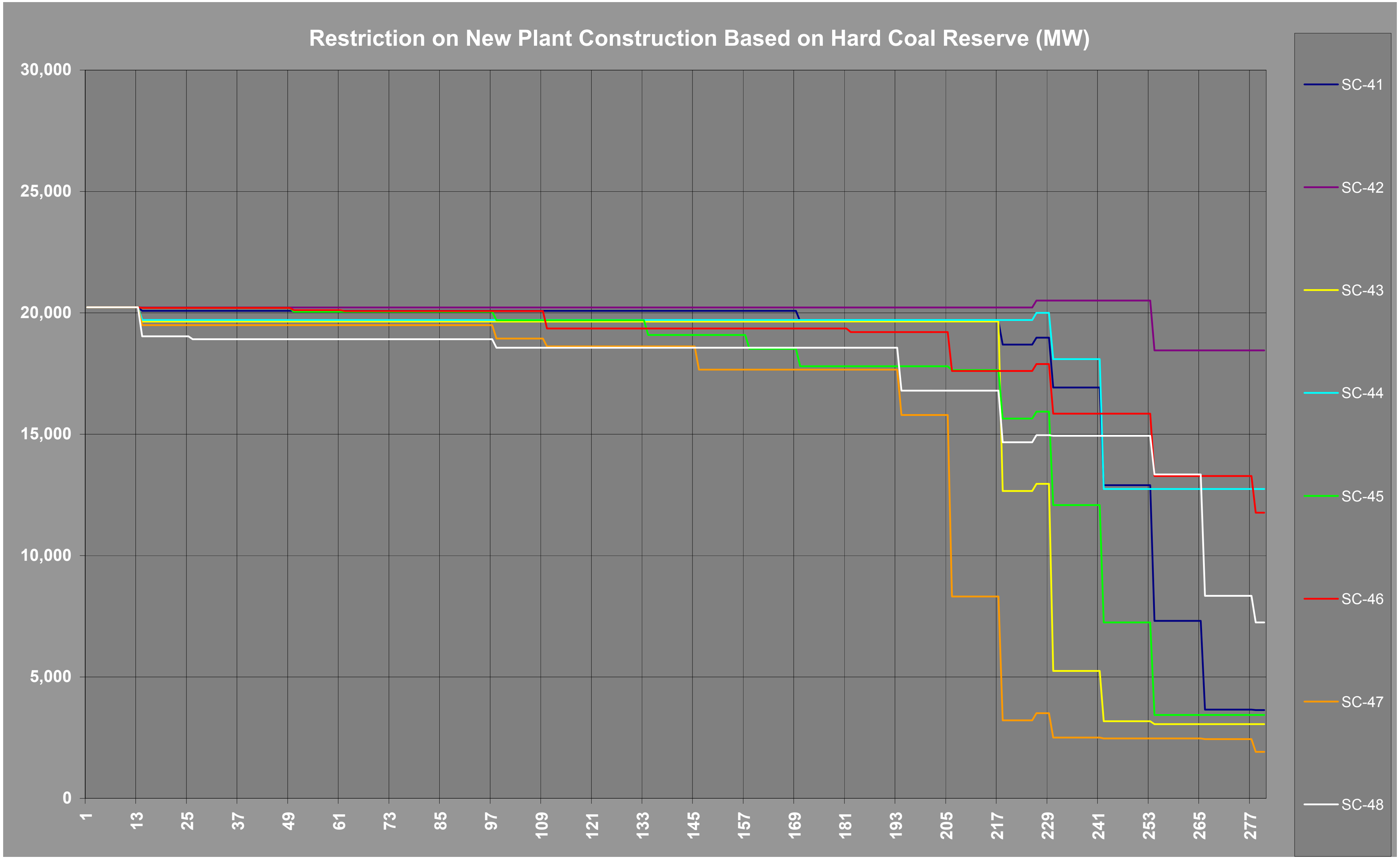

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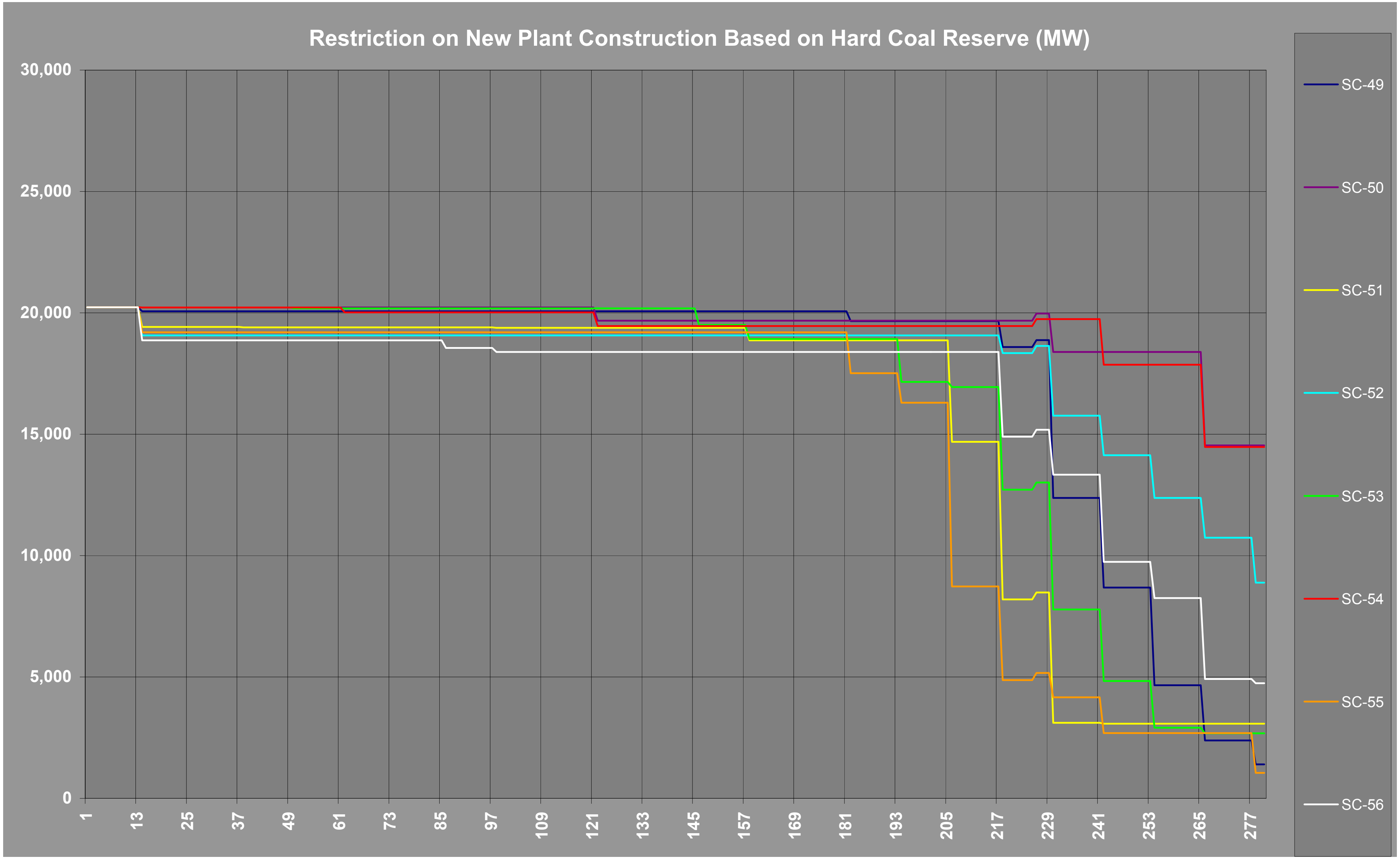
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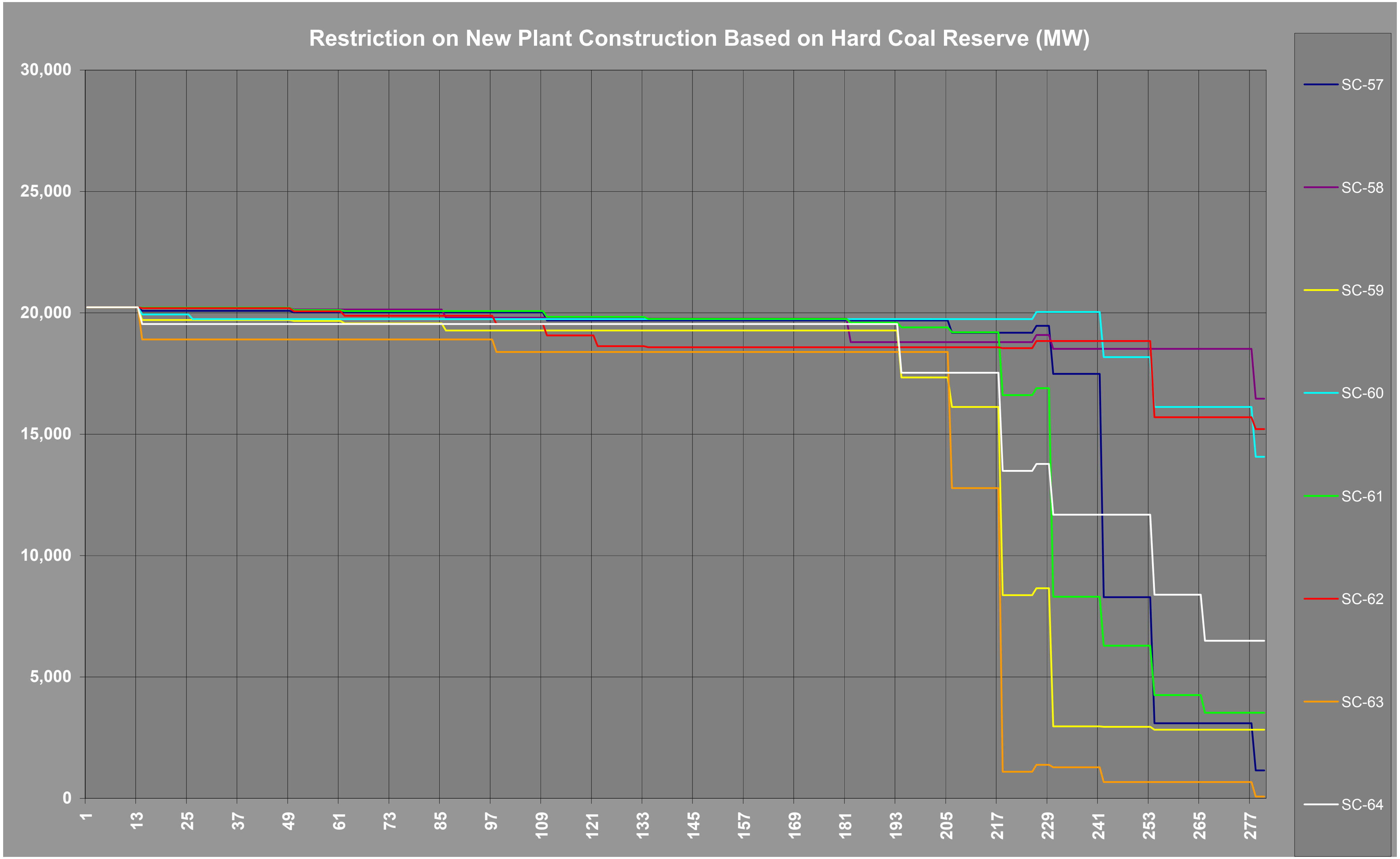

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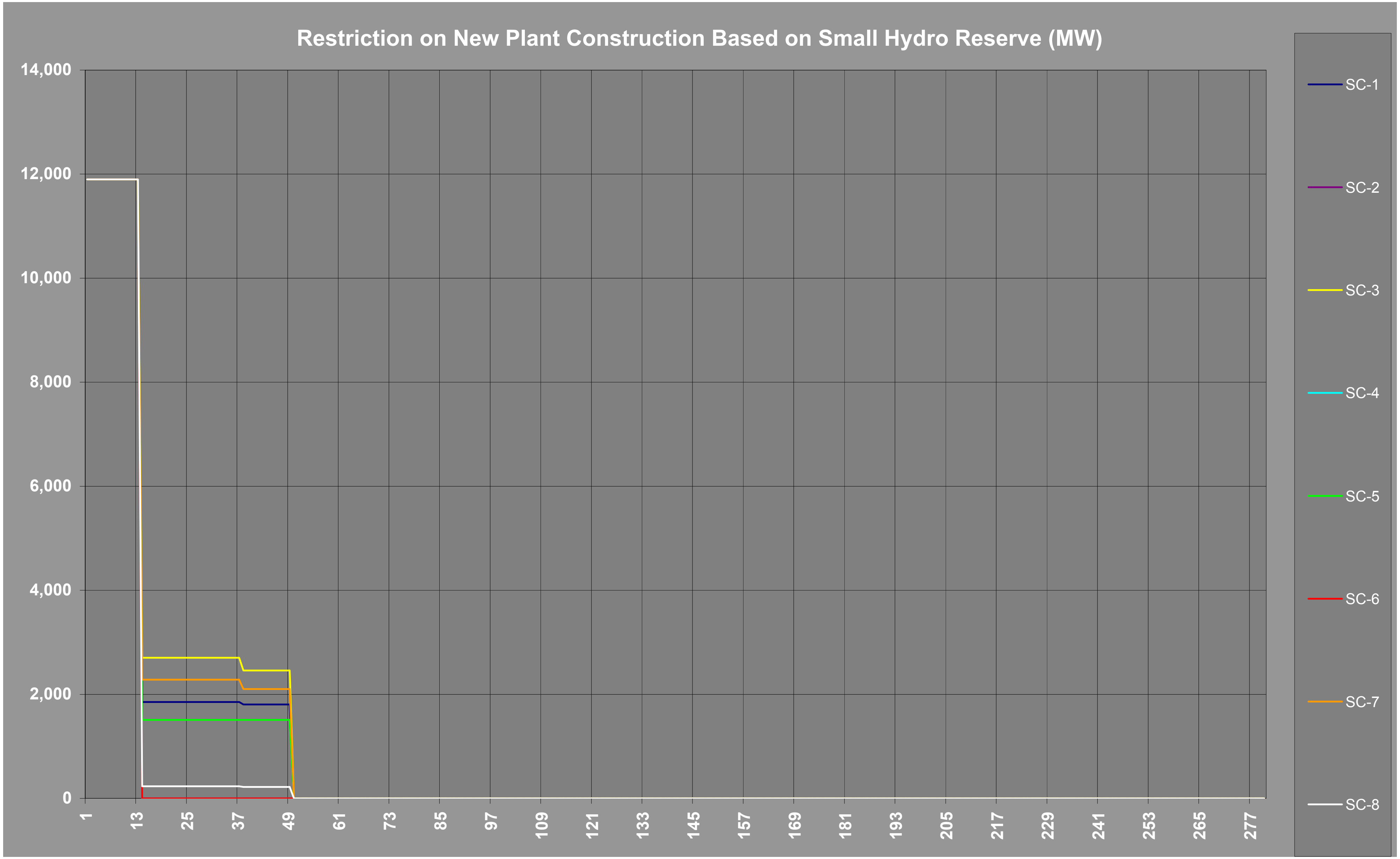
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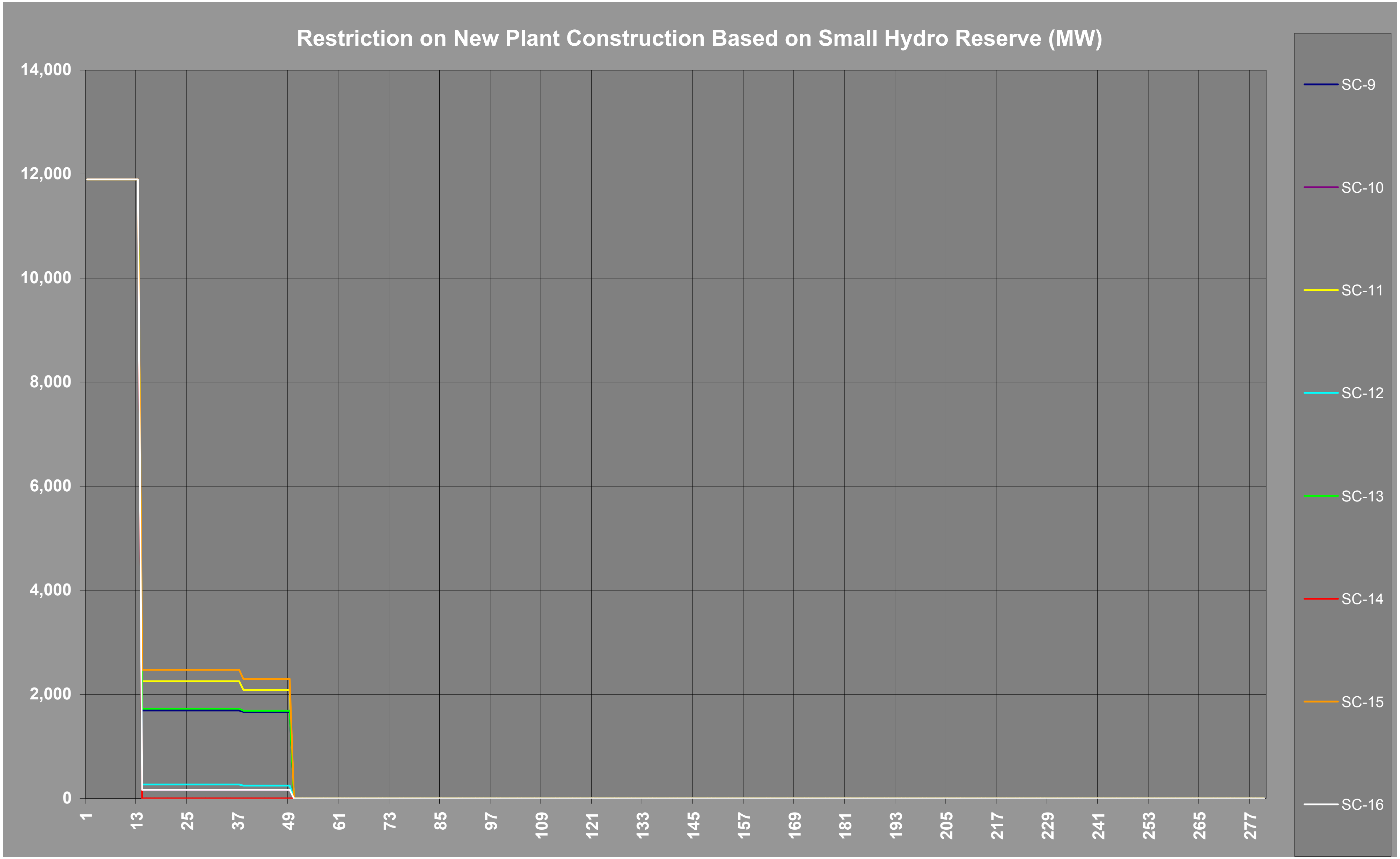
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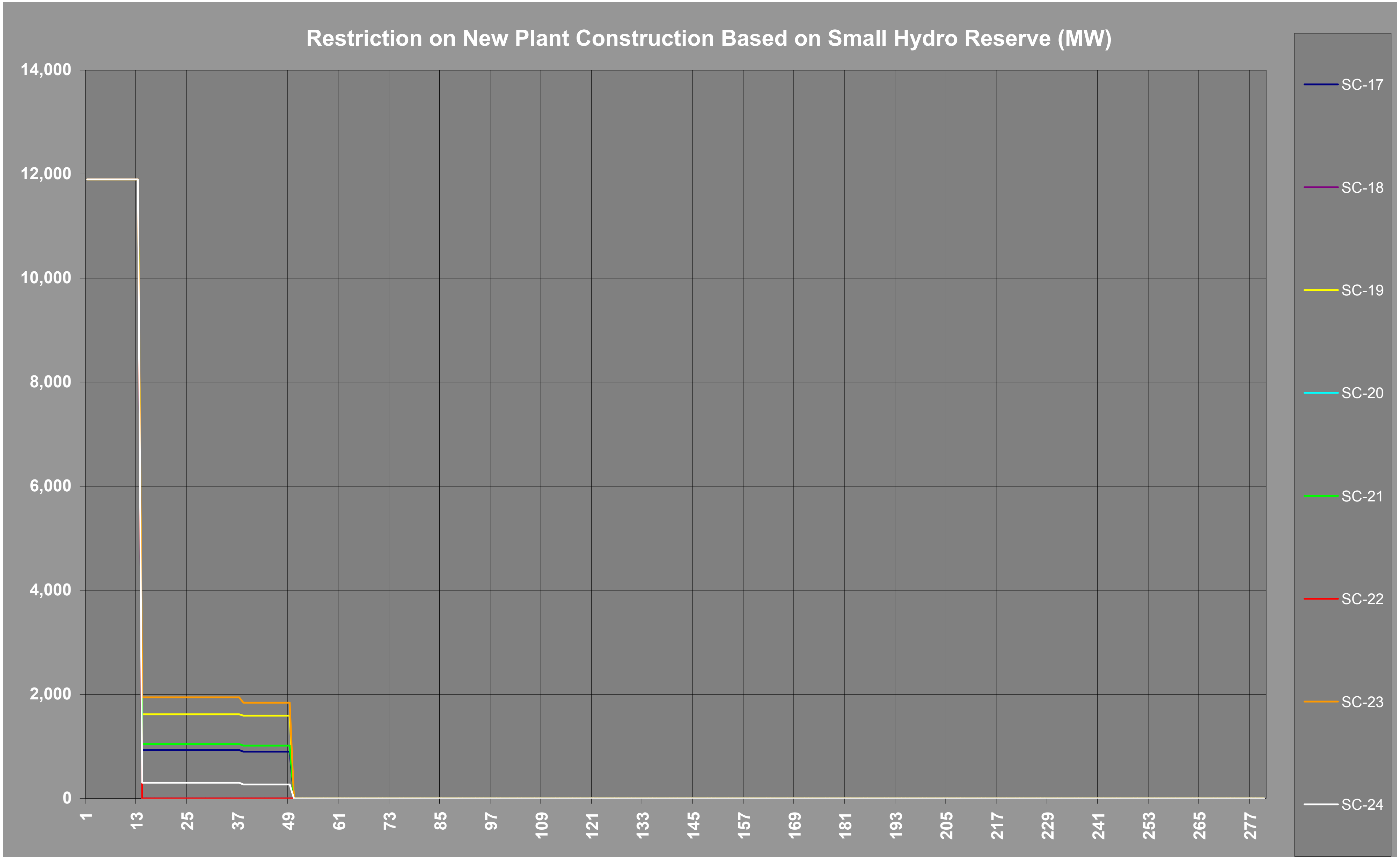
Restriction on New Plant Construction Based on Small Hydro Reserve (MW)
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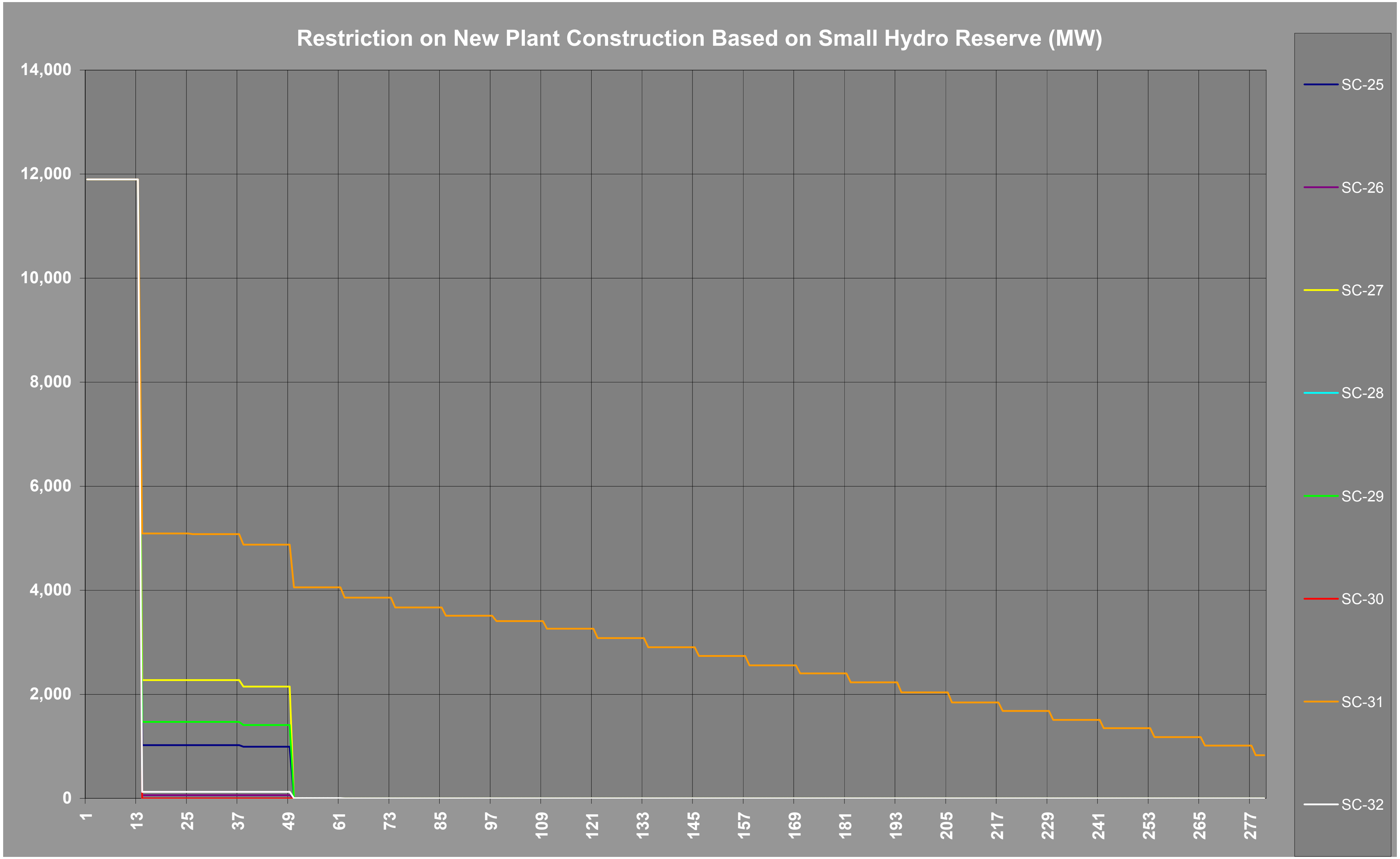

Restriction on New Plant Construction Based on Small Hydro Reserve (MW)
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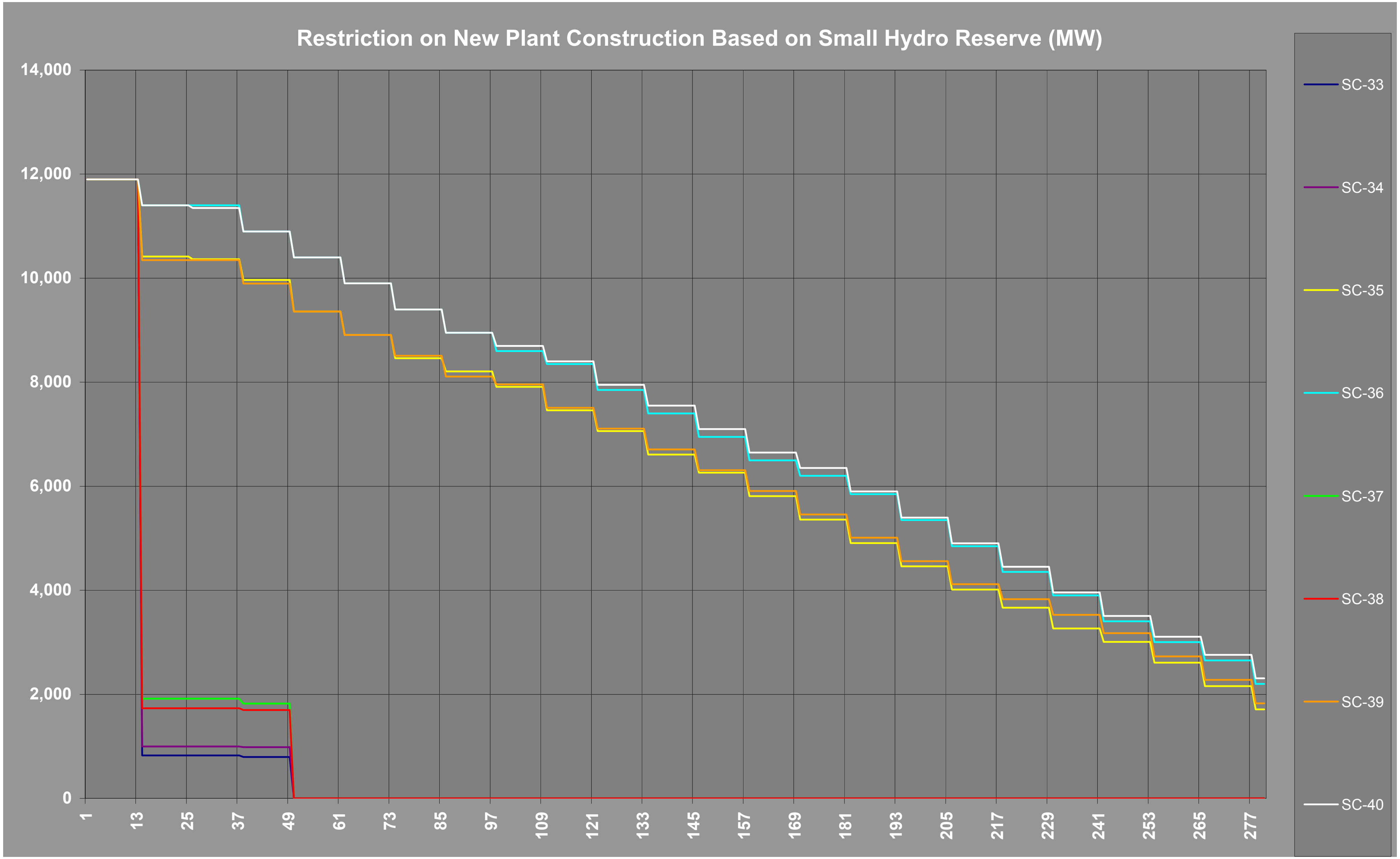

Restriction on New Plant Construction Based on Small Hydro Reserve (MW)
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Restriction on New Plant Construction Based on Small Hydro Reserve (MW)
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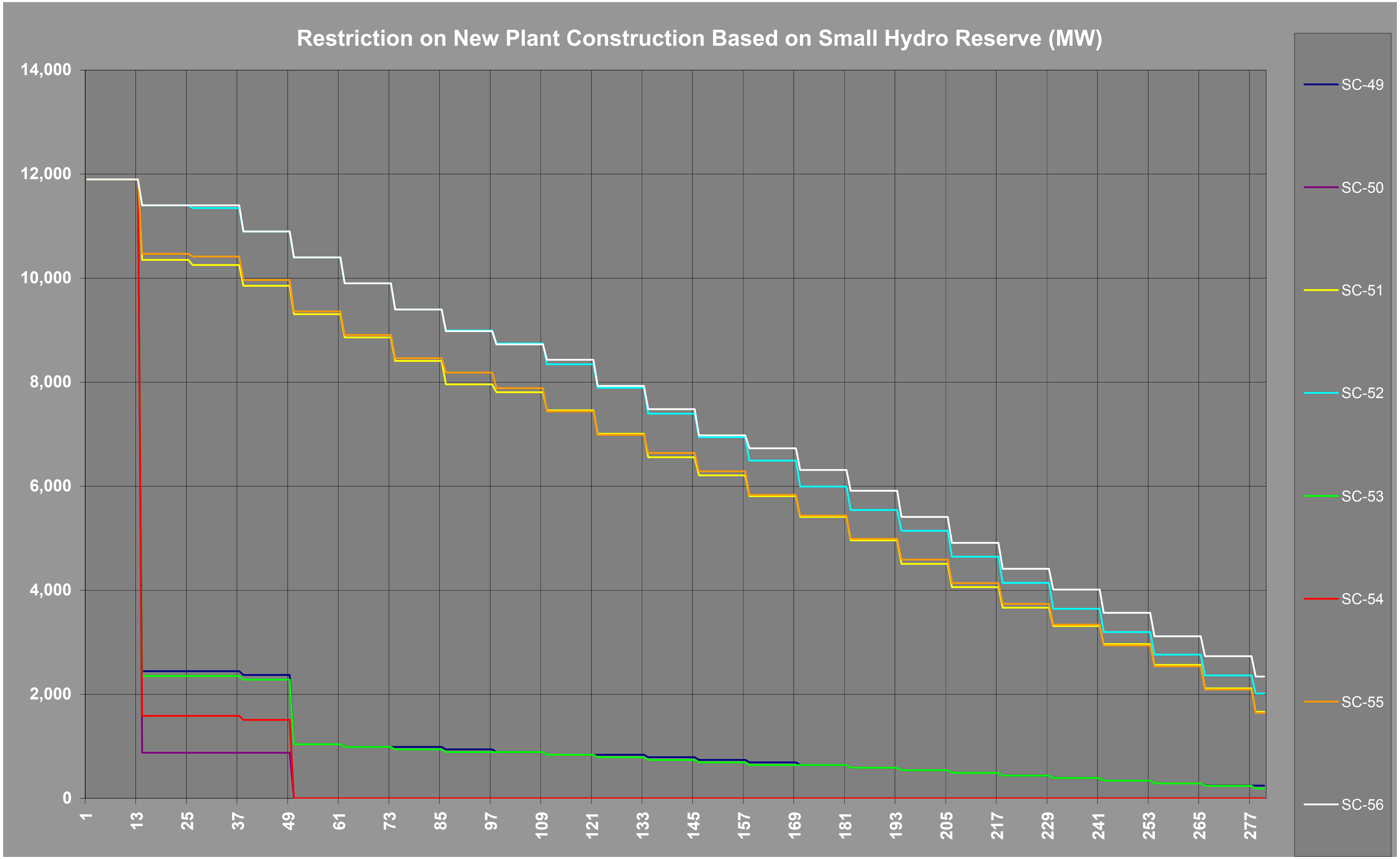
Restriction on New Plant Construction Based on Small Hydro Reserve (MW)
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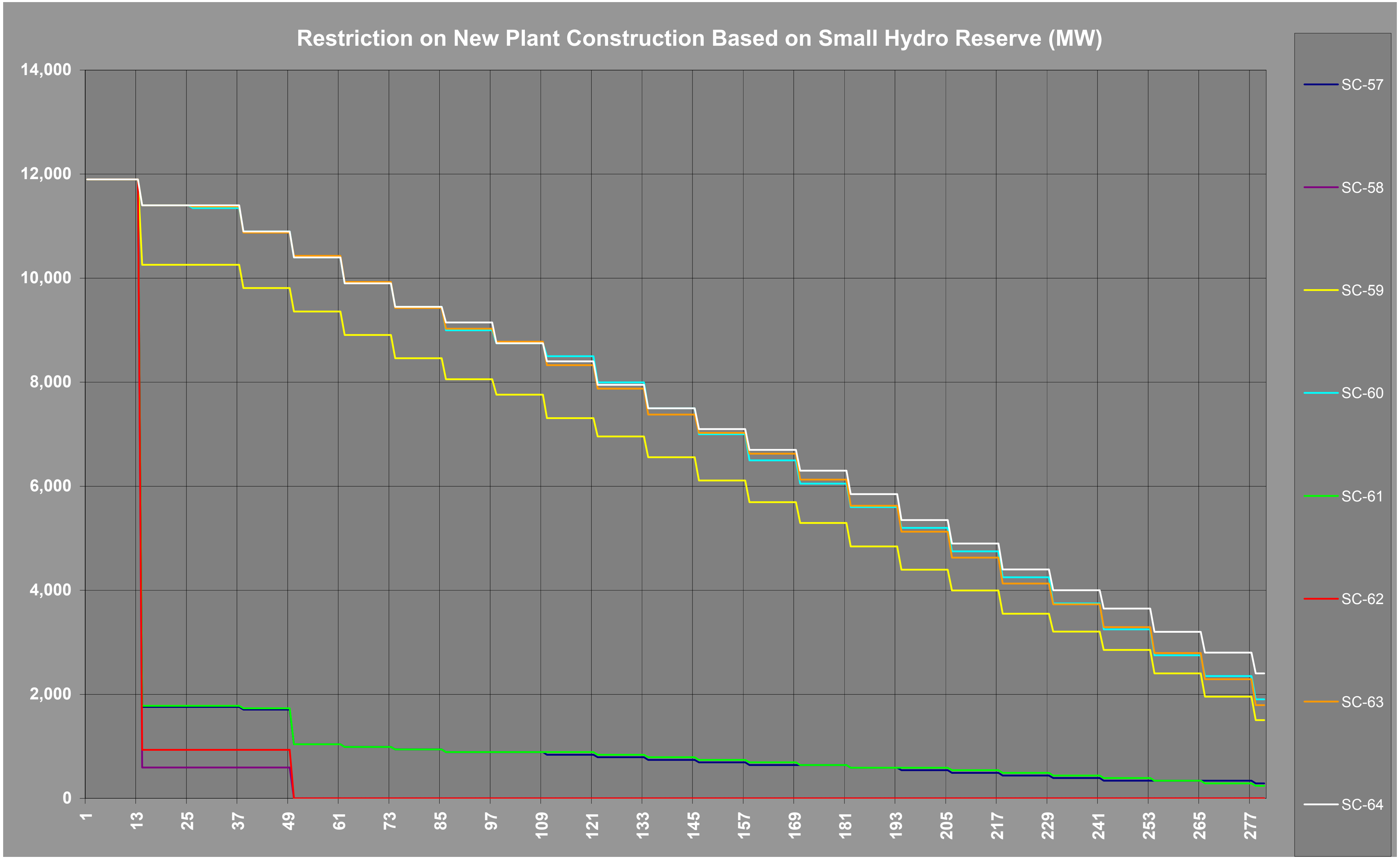

Restriction on New Plant Construction Based on Small Hydro Reserve (MW)
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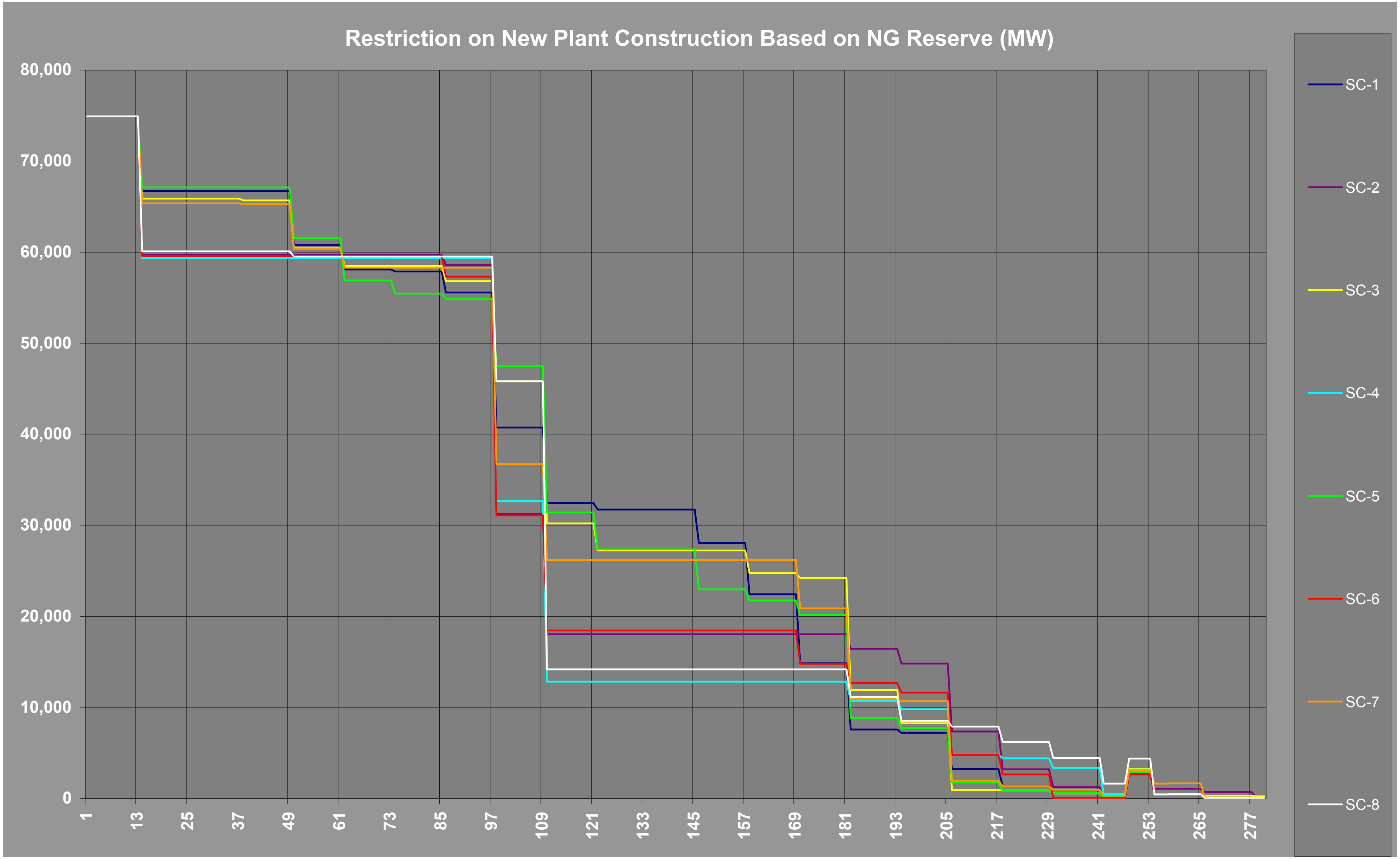
Restriction on New Plant Construction Based on NG Reserve (MW)
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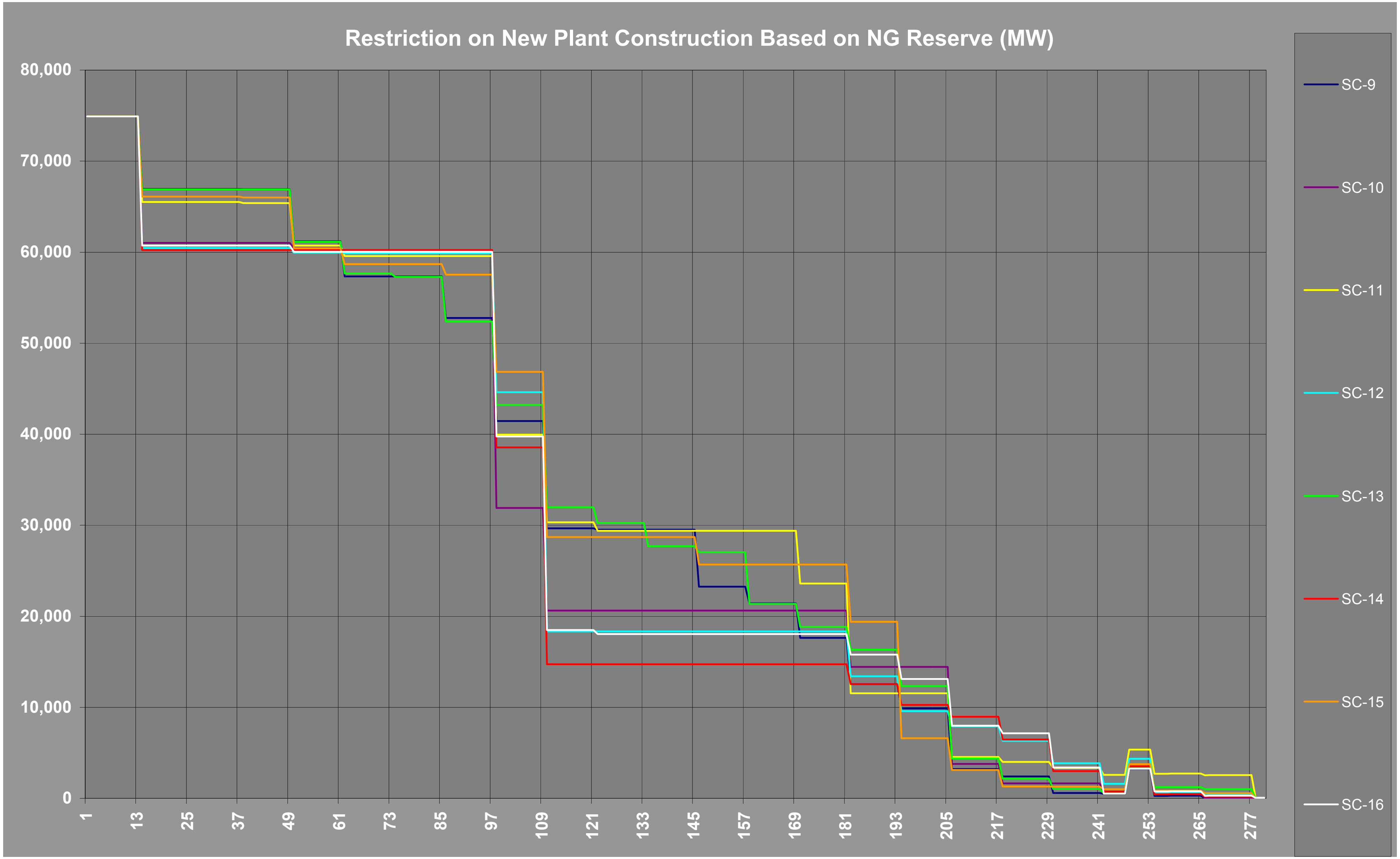

Restriction on New Plant Construction Based on NG Reserve (MW)
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Restriction on New Plant Construction Based on NG Reserve (MW)
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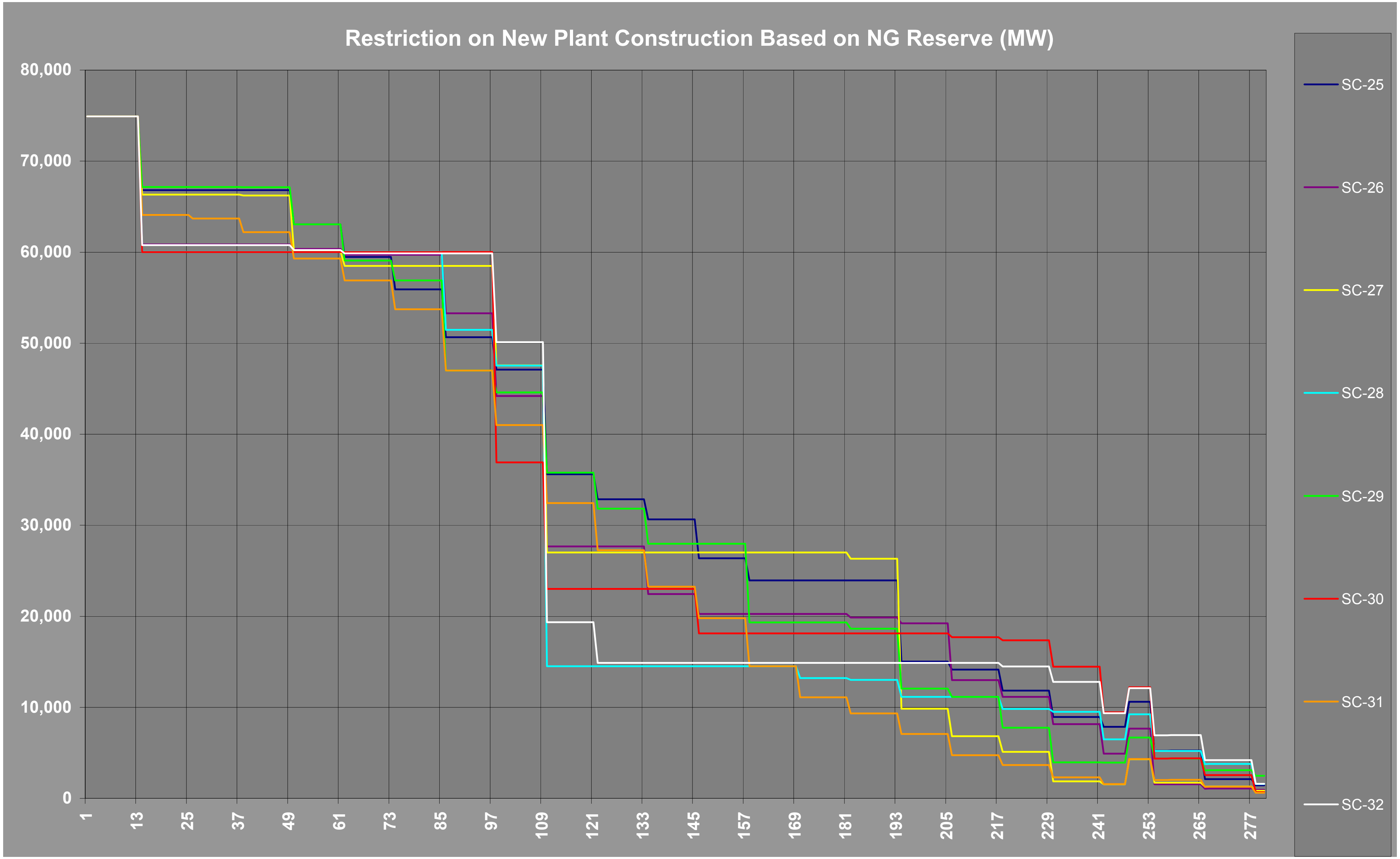

Restriction on New Plant Construction Based on NG Reserve (MW)
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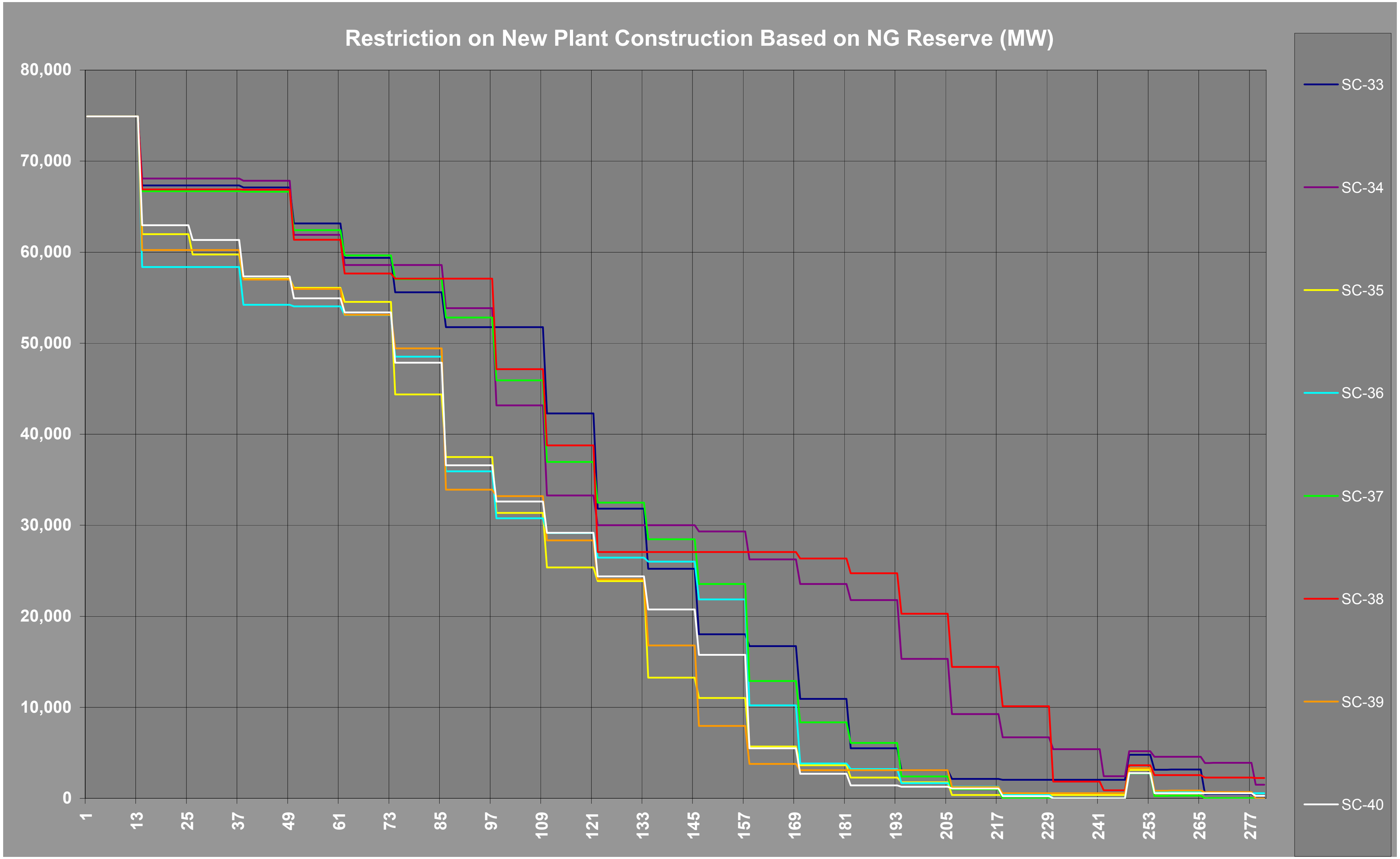

Restriction on New Plant Construction Based on NG Reserve (MW)
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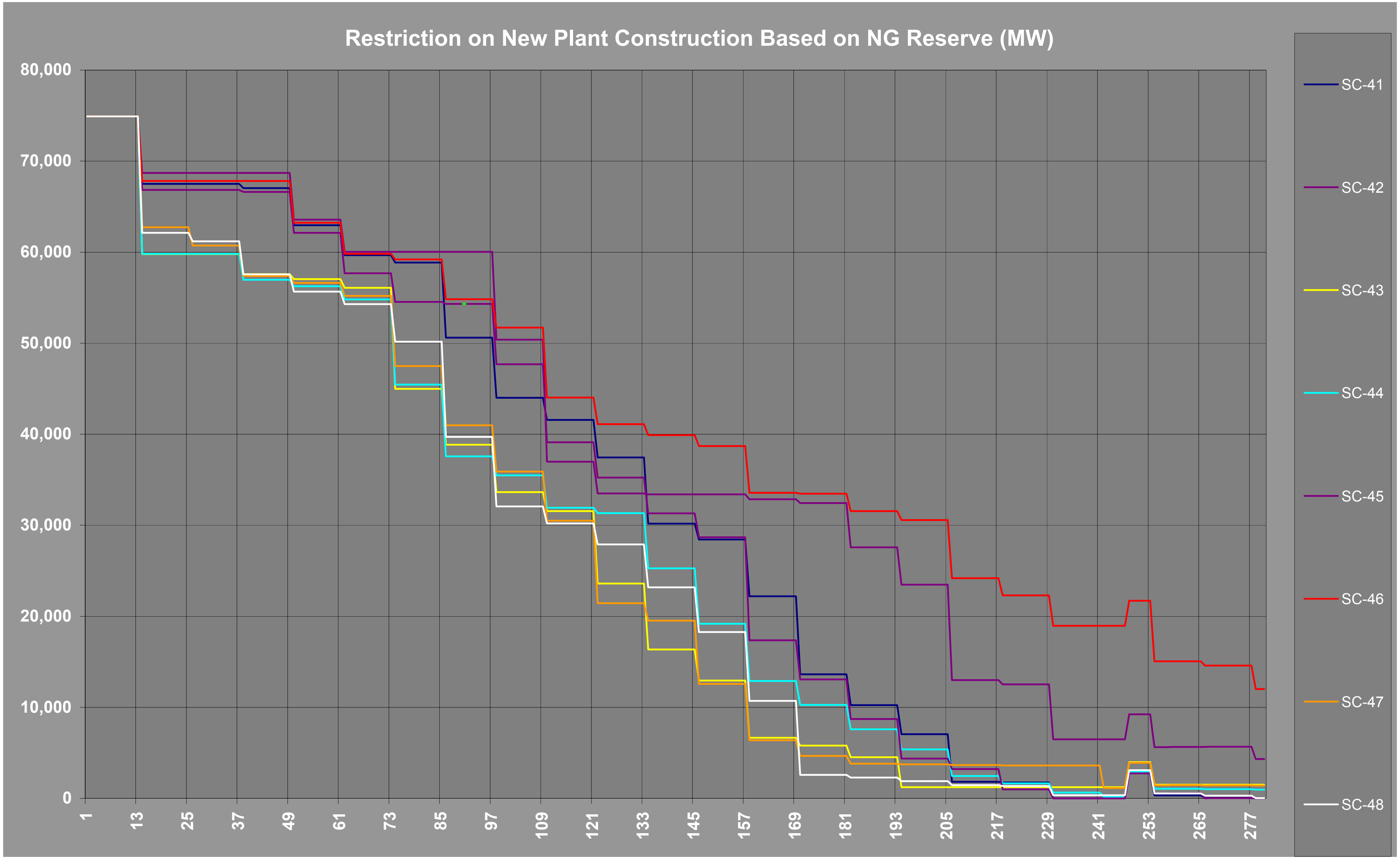

Restriction on New Plant Construction Based on NG Reserve (MW)
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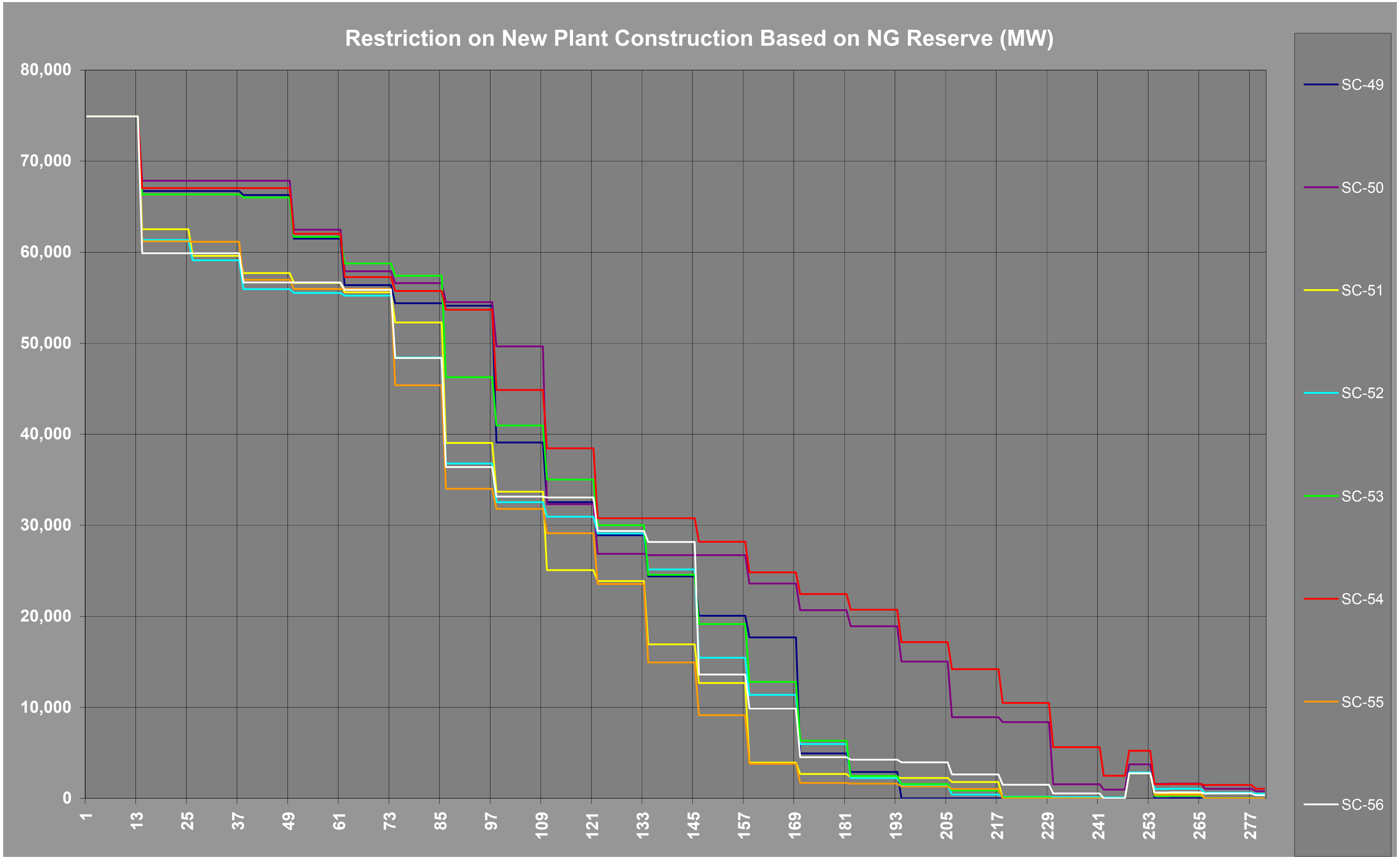
Restriction on New Plant Construction Based on NG Reserve (MW)
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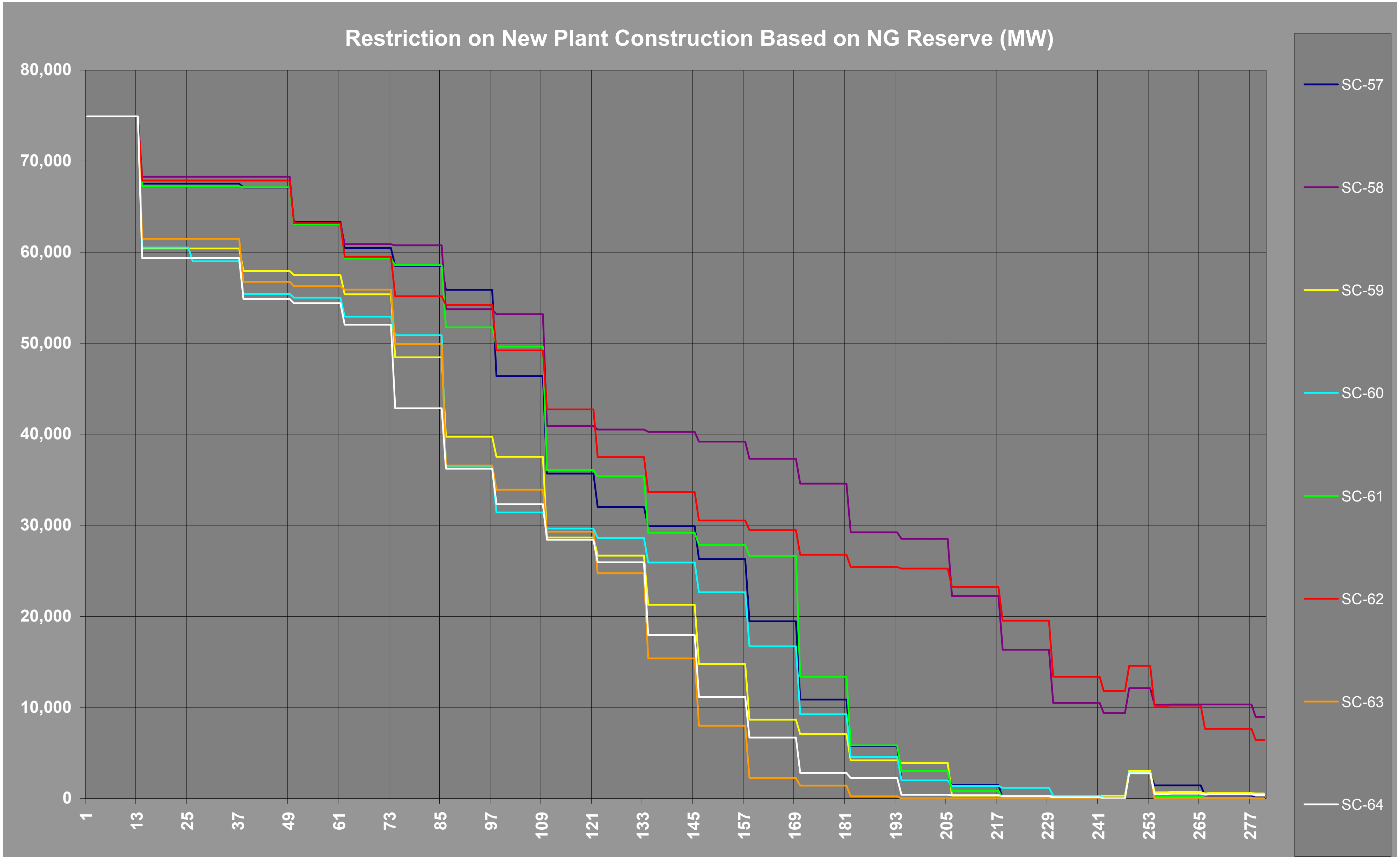
Restriction on New Plant Construction Based on NG Reserve (MW)
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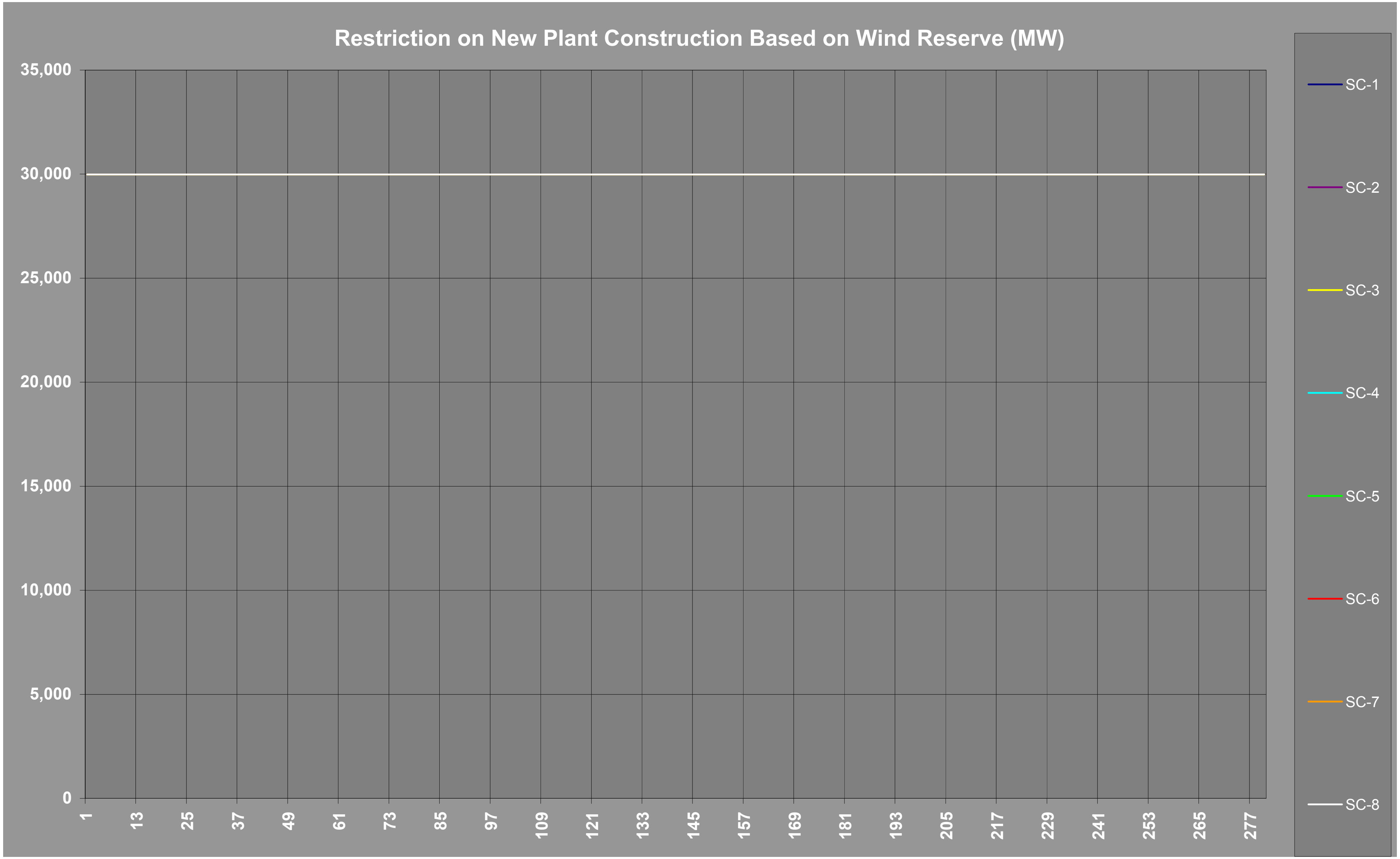

Restriction on New Plant Construction Based on Wind Reserve (MW)
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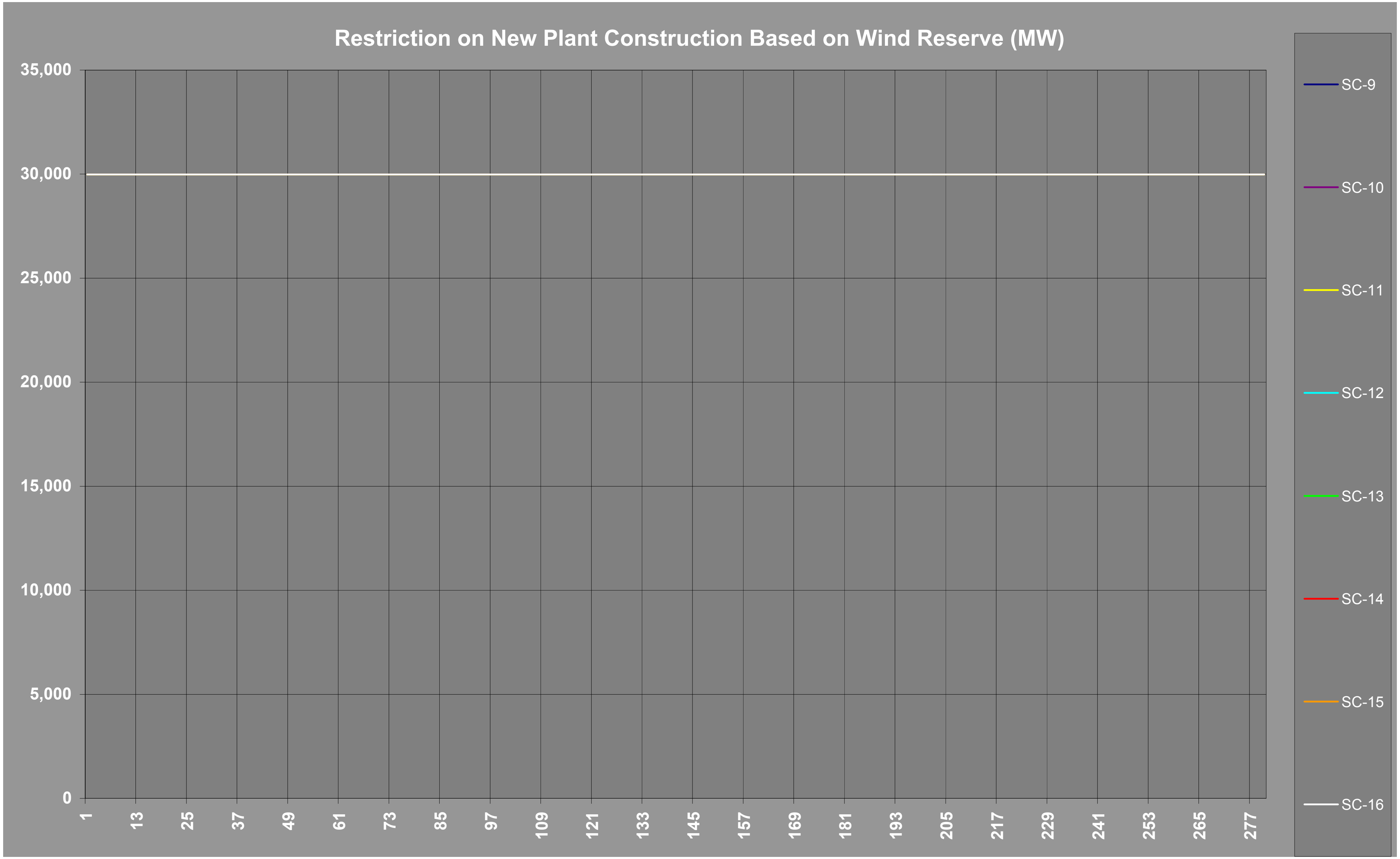
Restriction on New Plant Construction Based on Wind Reserve (MW)
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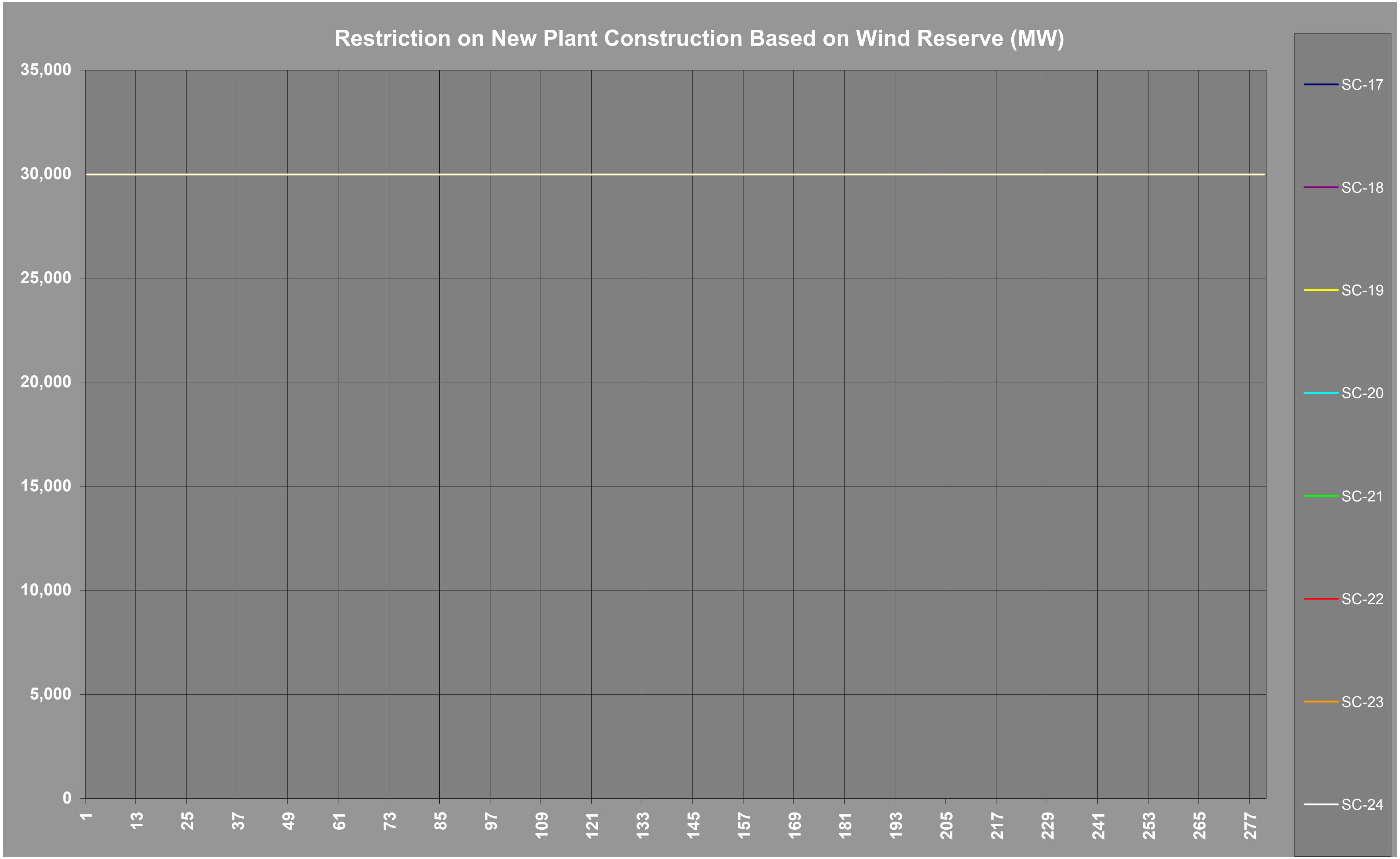

Restriction on New Plant Construction Based on Wind Reserve (MW)
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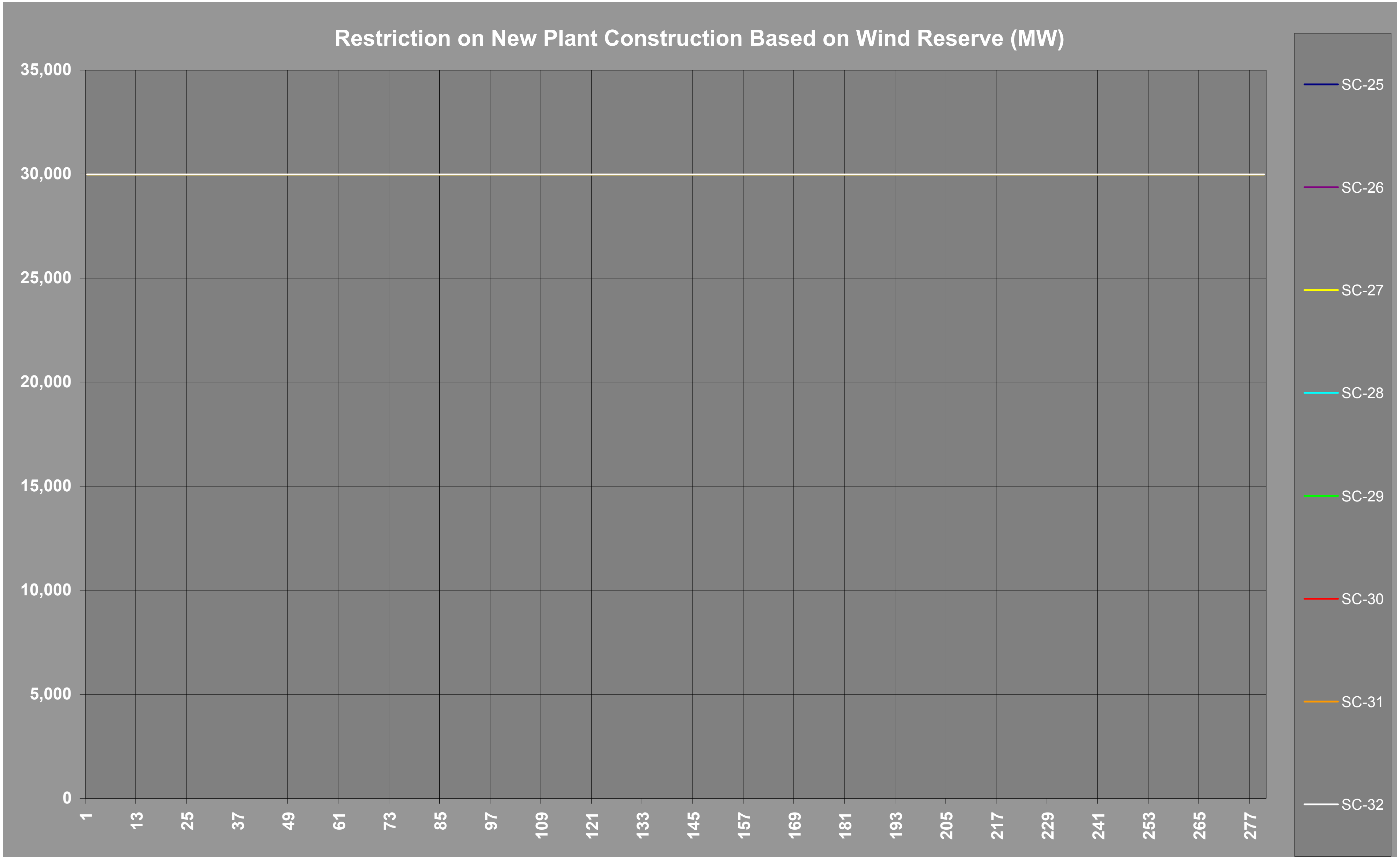
Restriction on New Plant Construction Based on Wind Reserve (MW)
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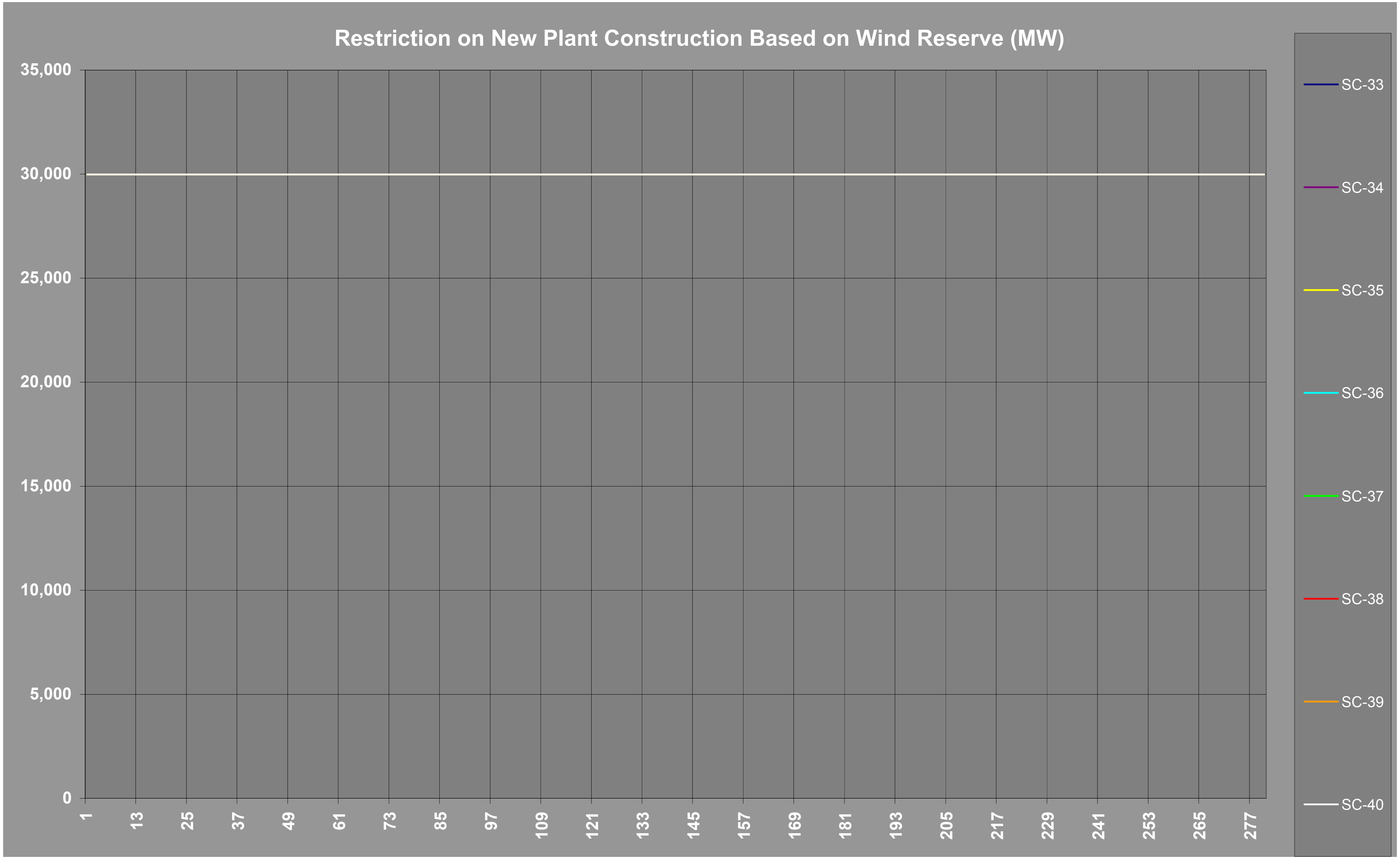

Restriction on New Plant Construction Based on Wind Reserve (MW)
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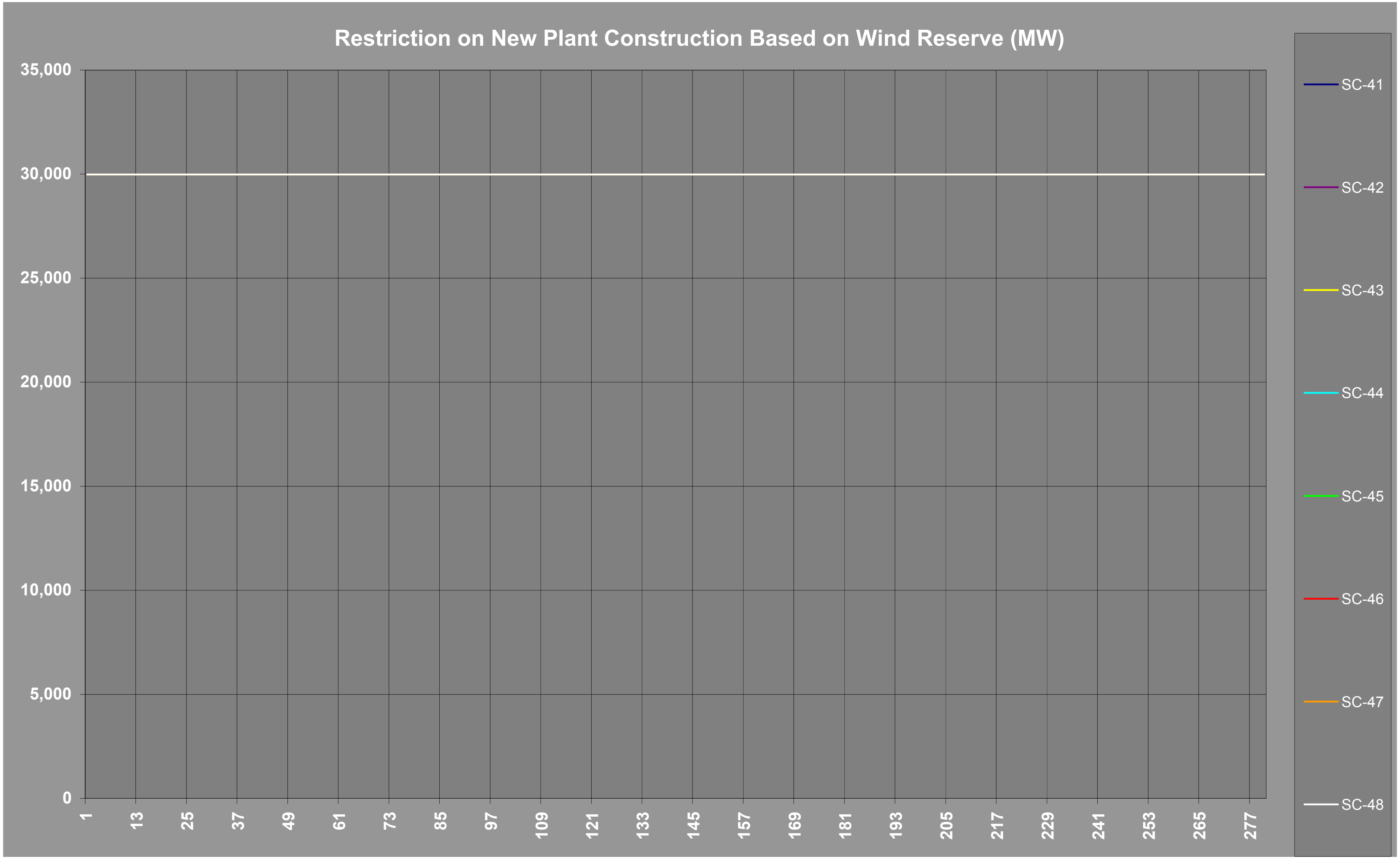

Restriction on New Plant Construction Based on Wind Reserve (MW)
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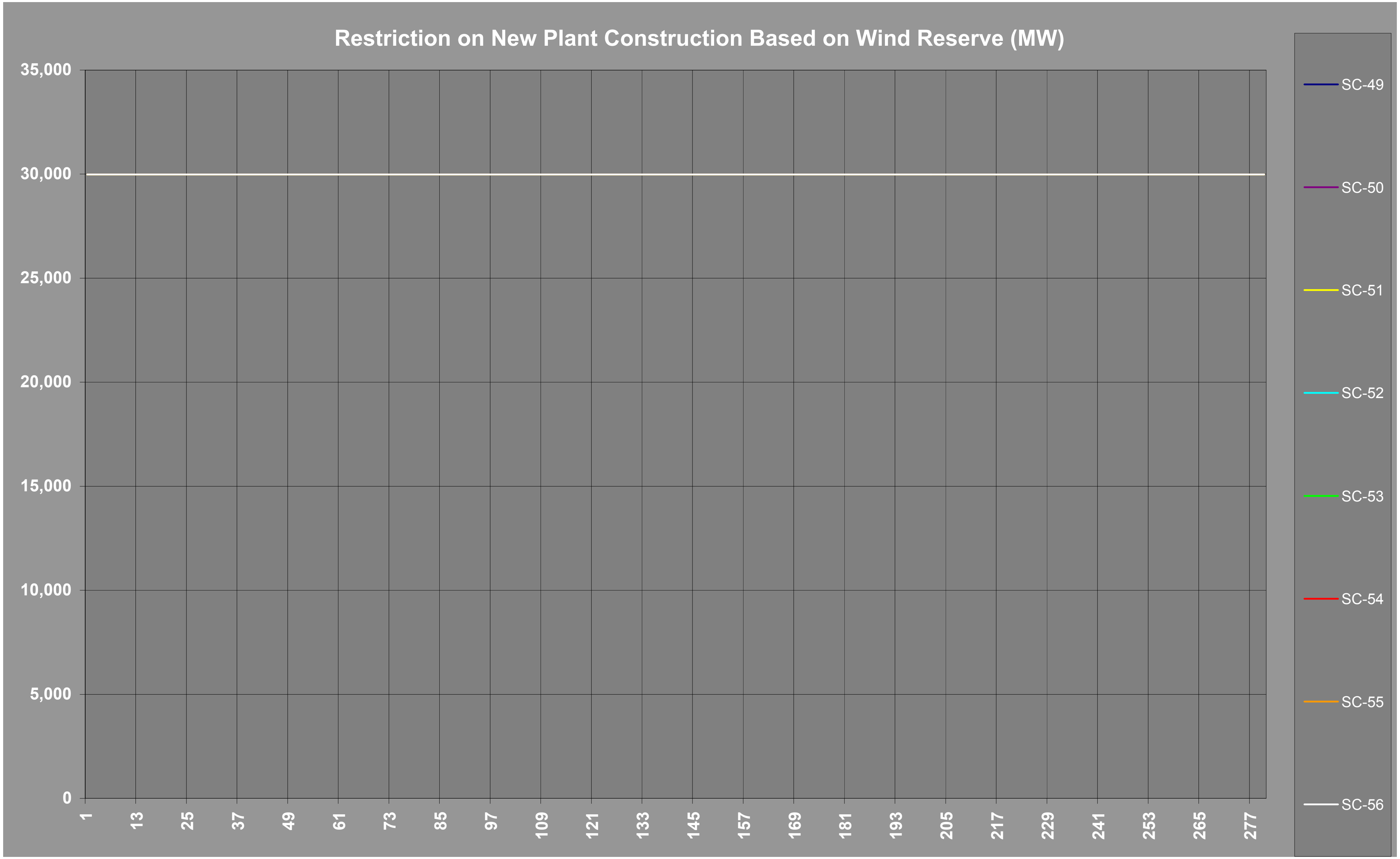

Restriction on New Plant Construction Based on Wind Reserve (MW)
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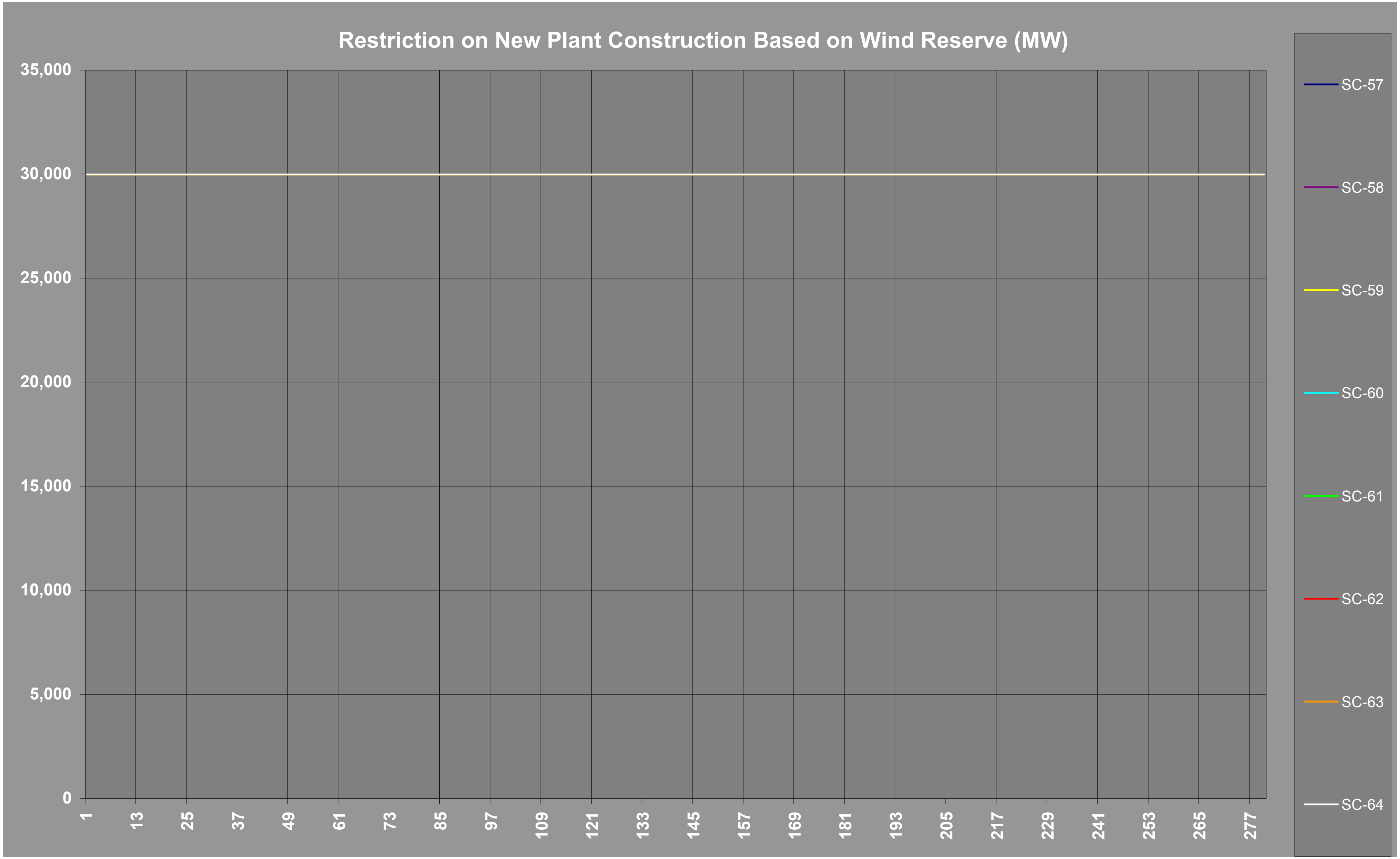
Restriction on New Plant Construction Based on Wind Reserve (MW)
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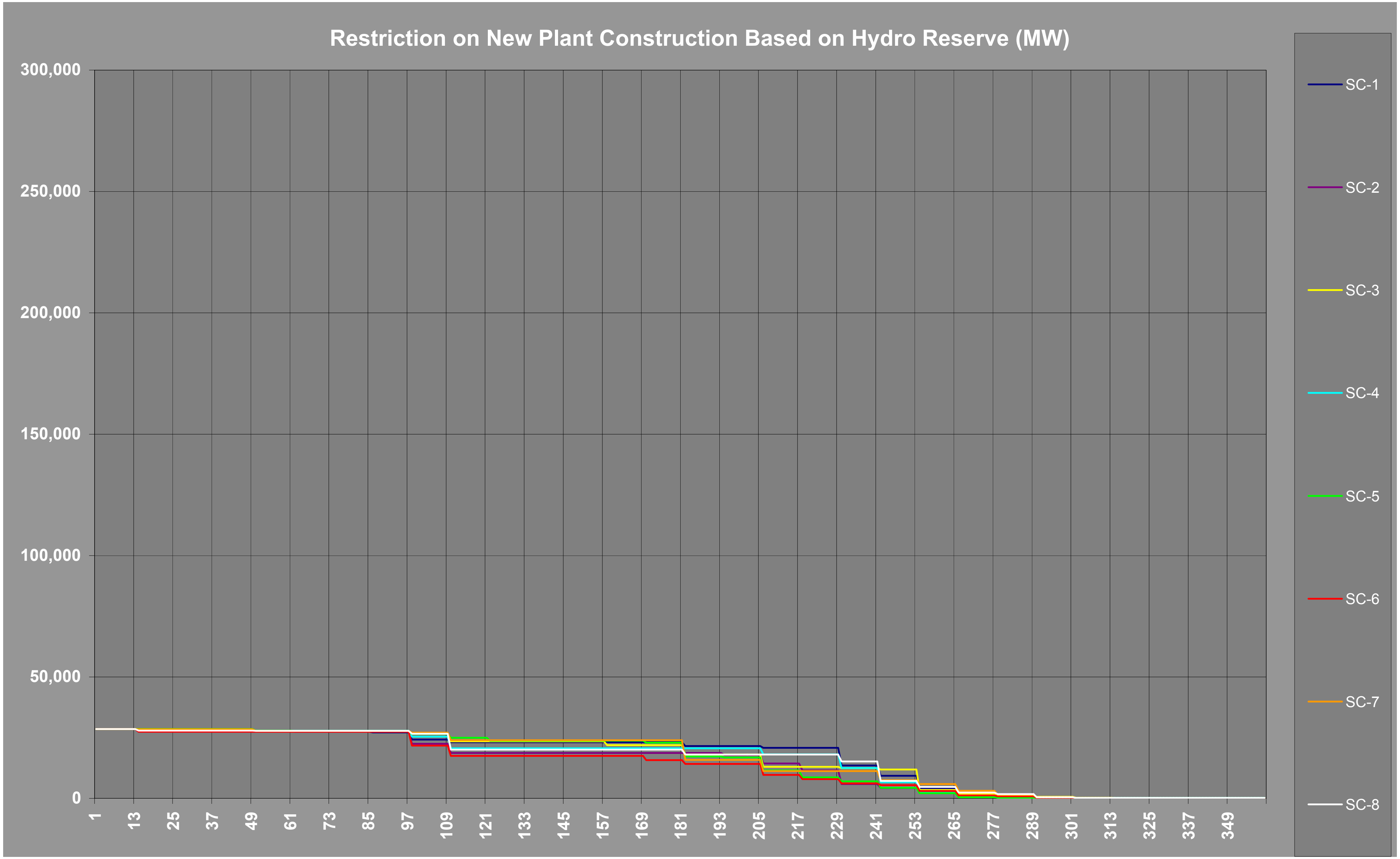

Restriction on New Plant Construction Based on Hydro Reserve (MW)
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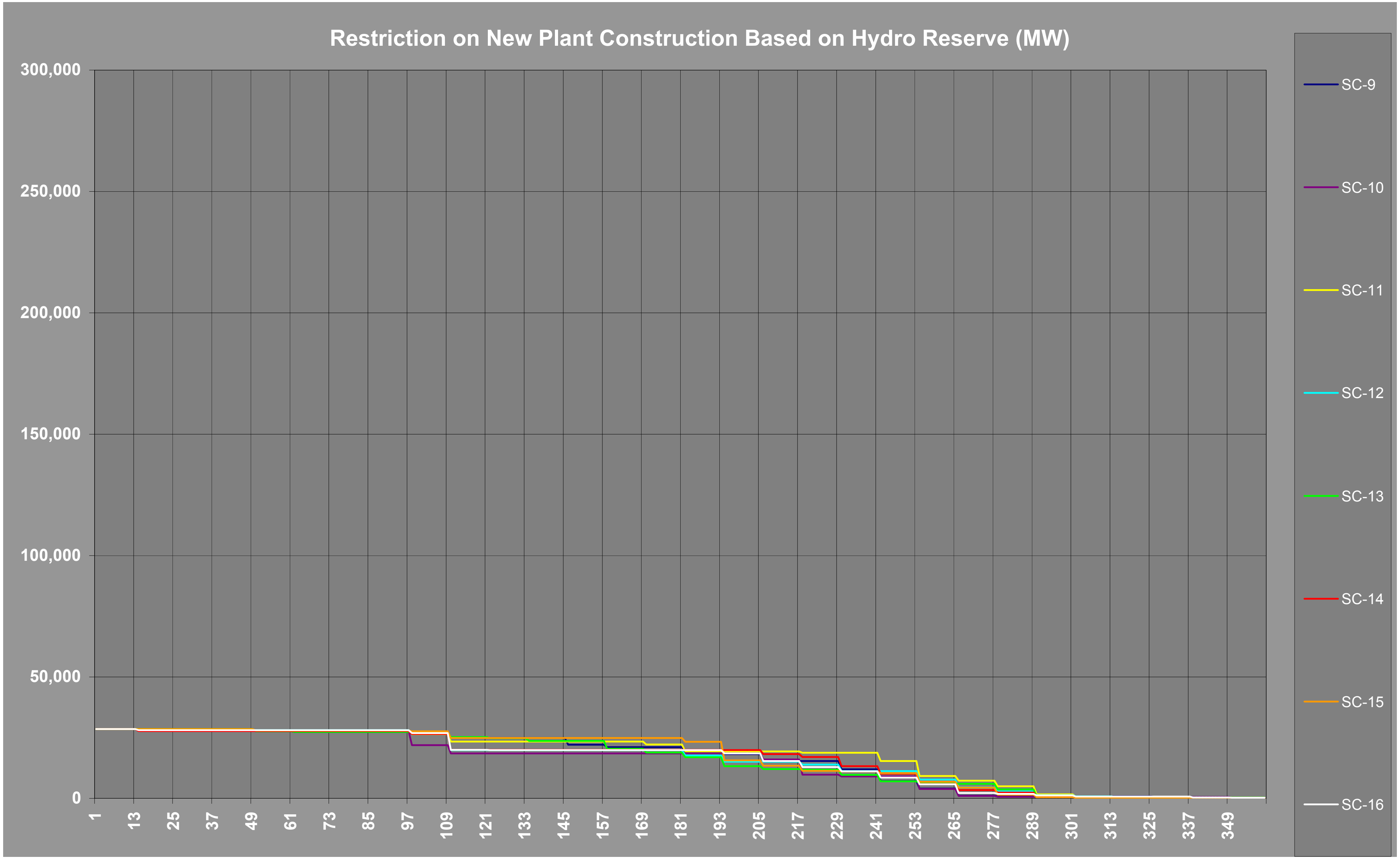

Restriction on New Plant Construction Based on Hydro Reserve (MW)
300,000
250,000
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150,000
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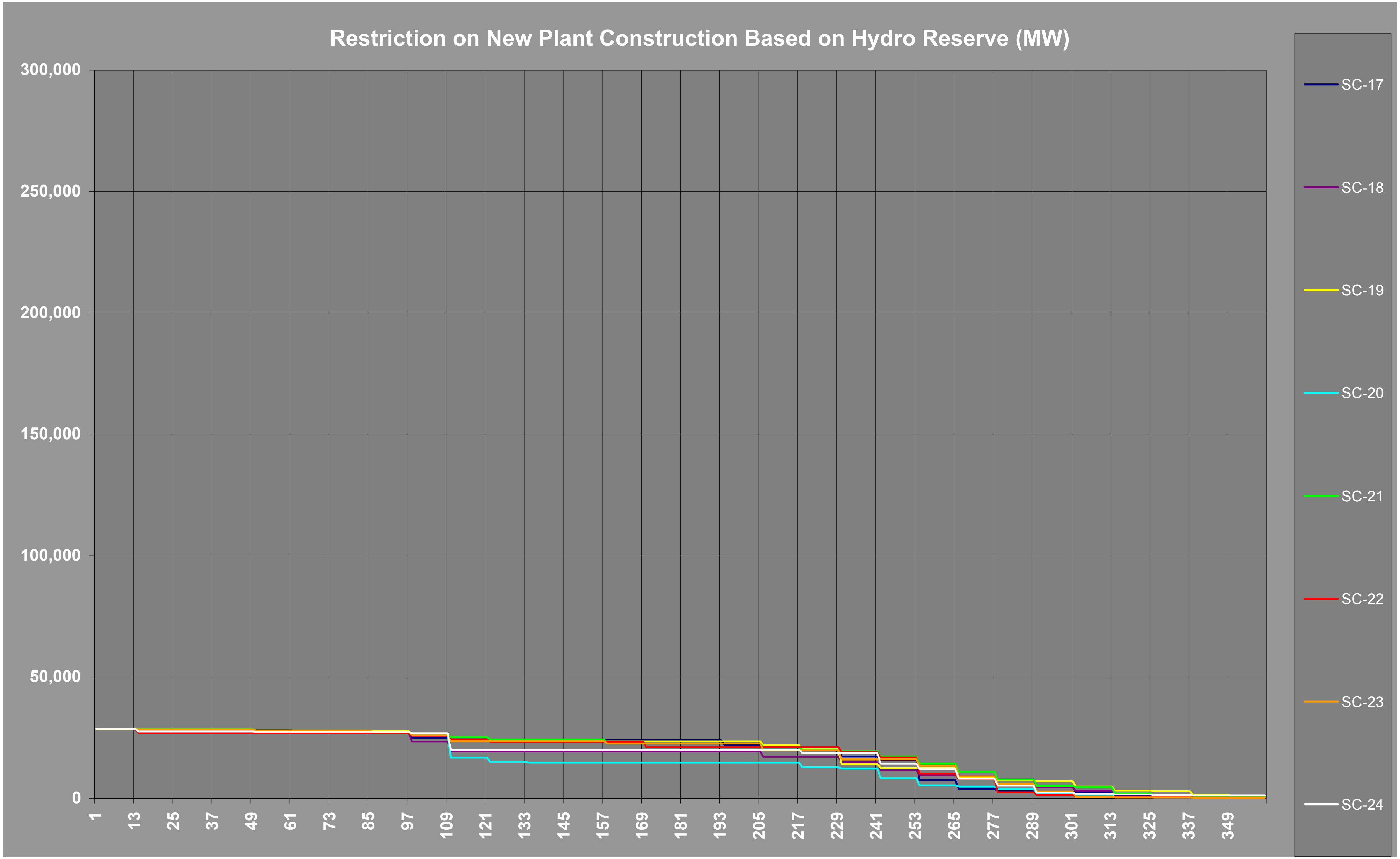

Restriction on New Plant Construction Based on Hydro Reserve (MW)
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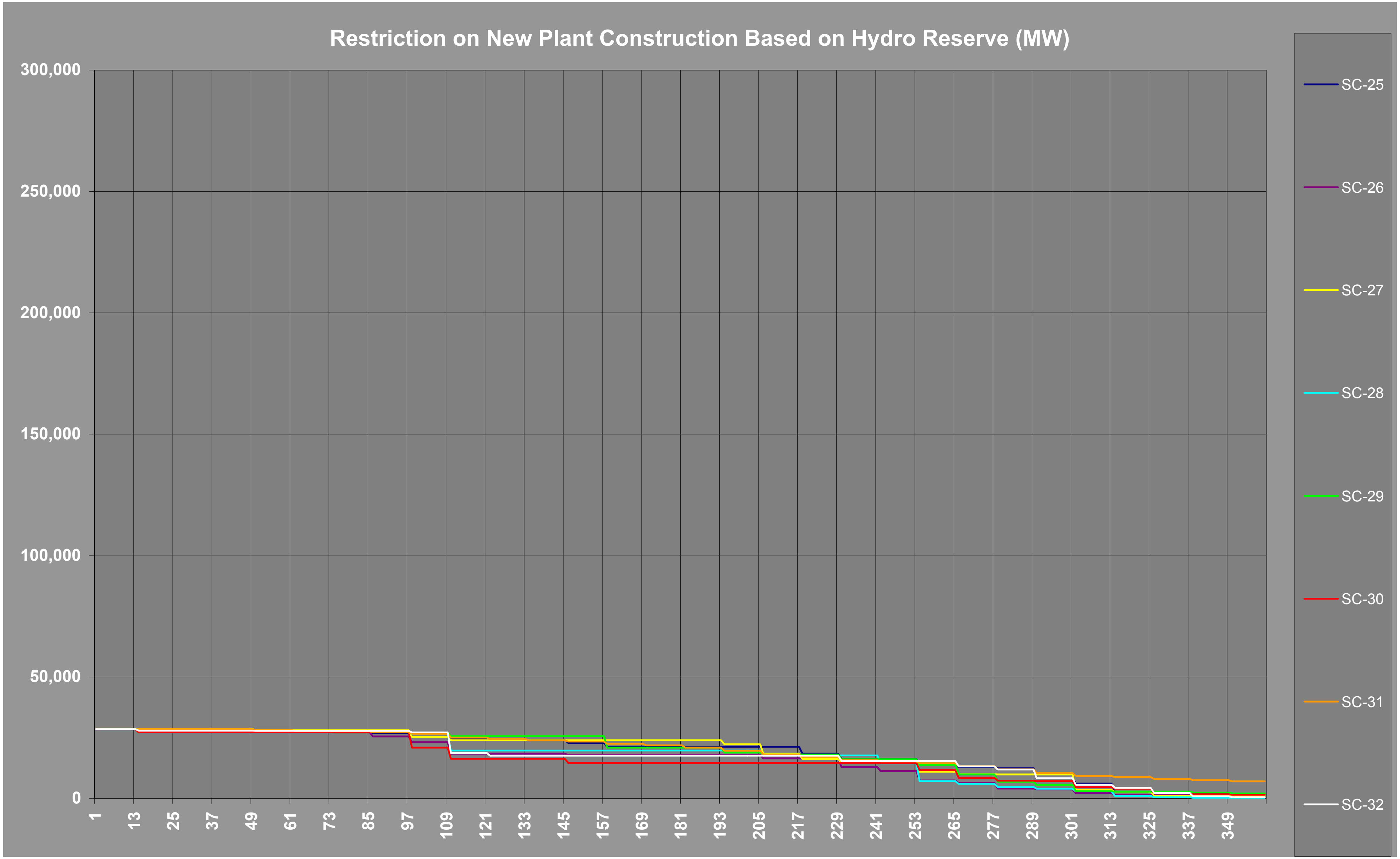

Restriction on New Plant Construction Based on Hydro Reserve (MW)
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Restriction on New Plant Construction Based on Hydro Reserve (MW)
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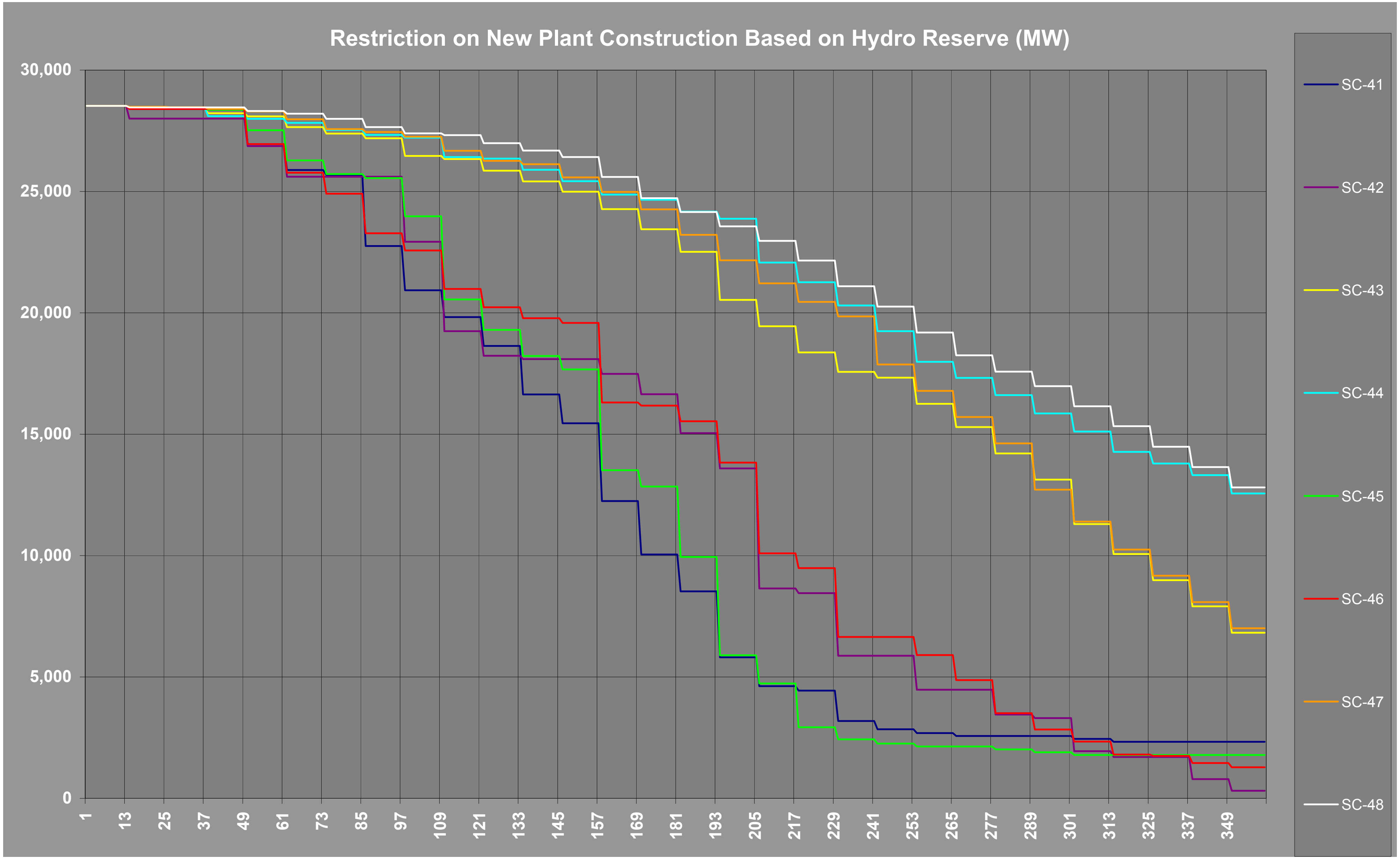

Restriction on New Plant Construction Based on Hydro Reserve (MW)
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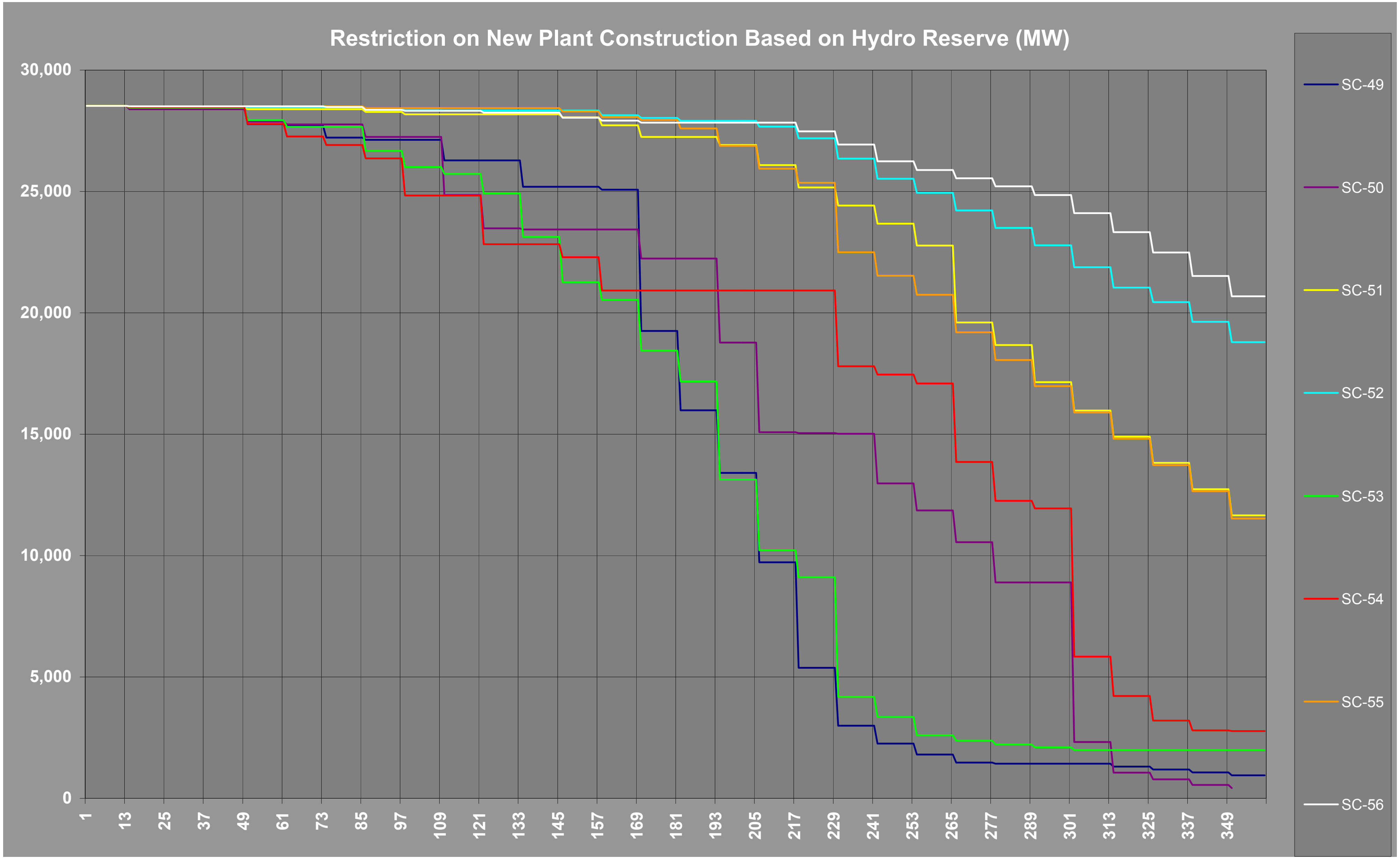

Restriction on New Plant Construction Based on Hydro Reserve (MW)
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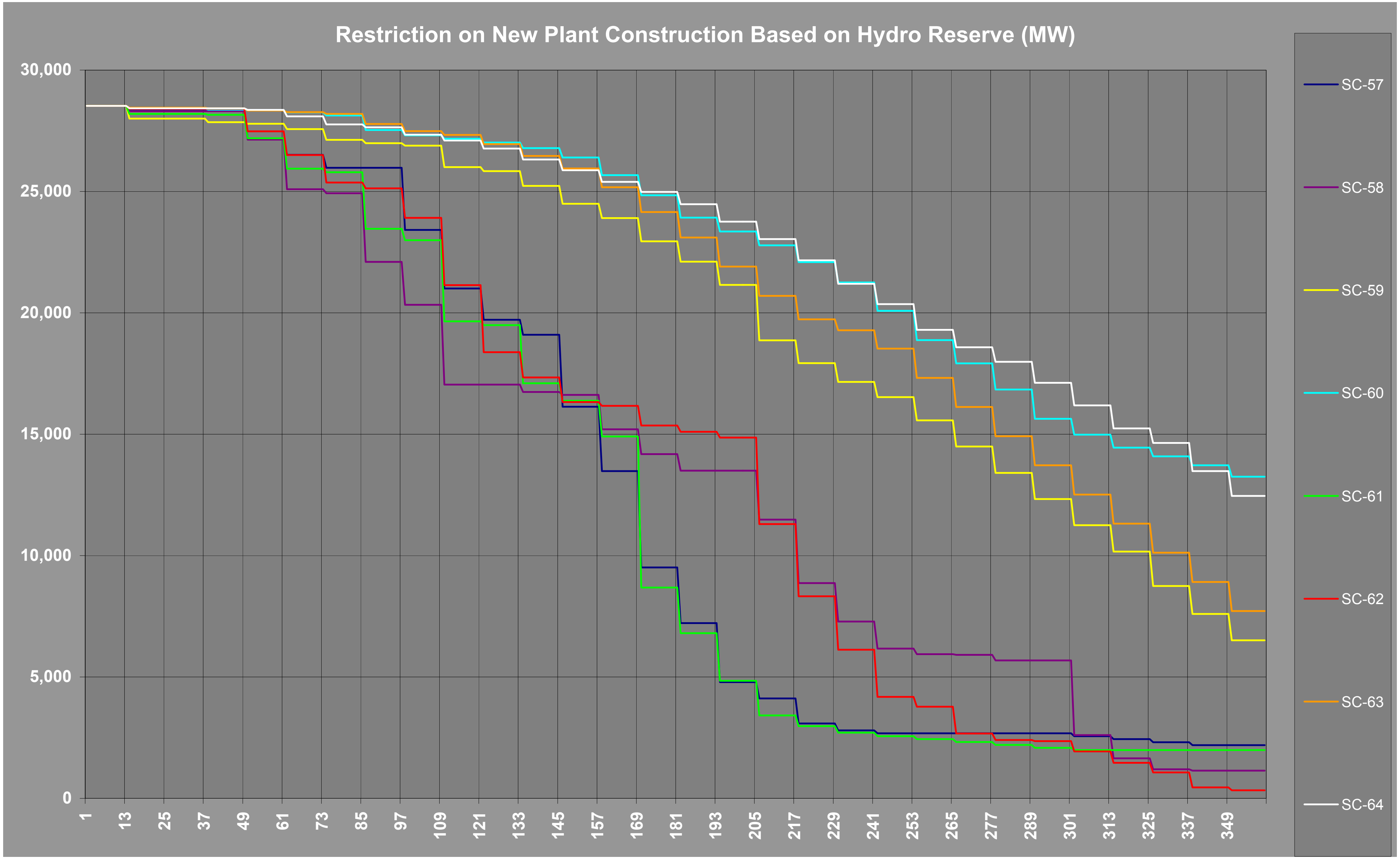

Restriction on New Plant Construction Based on Hydro Reserve (MW)
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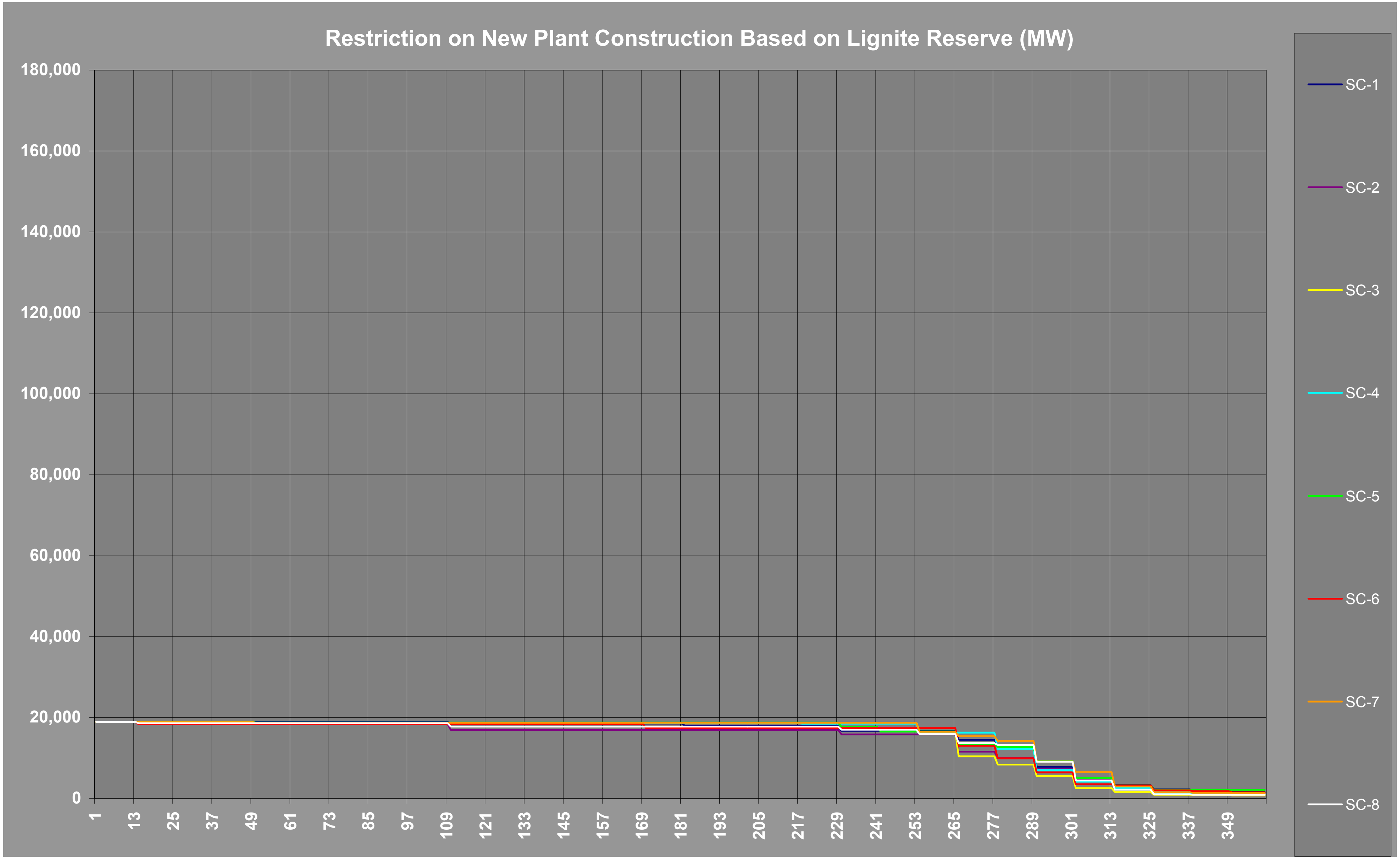
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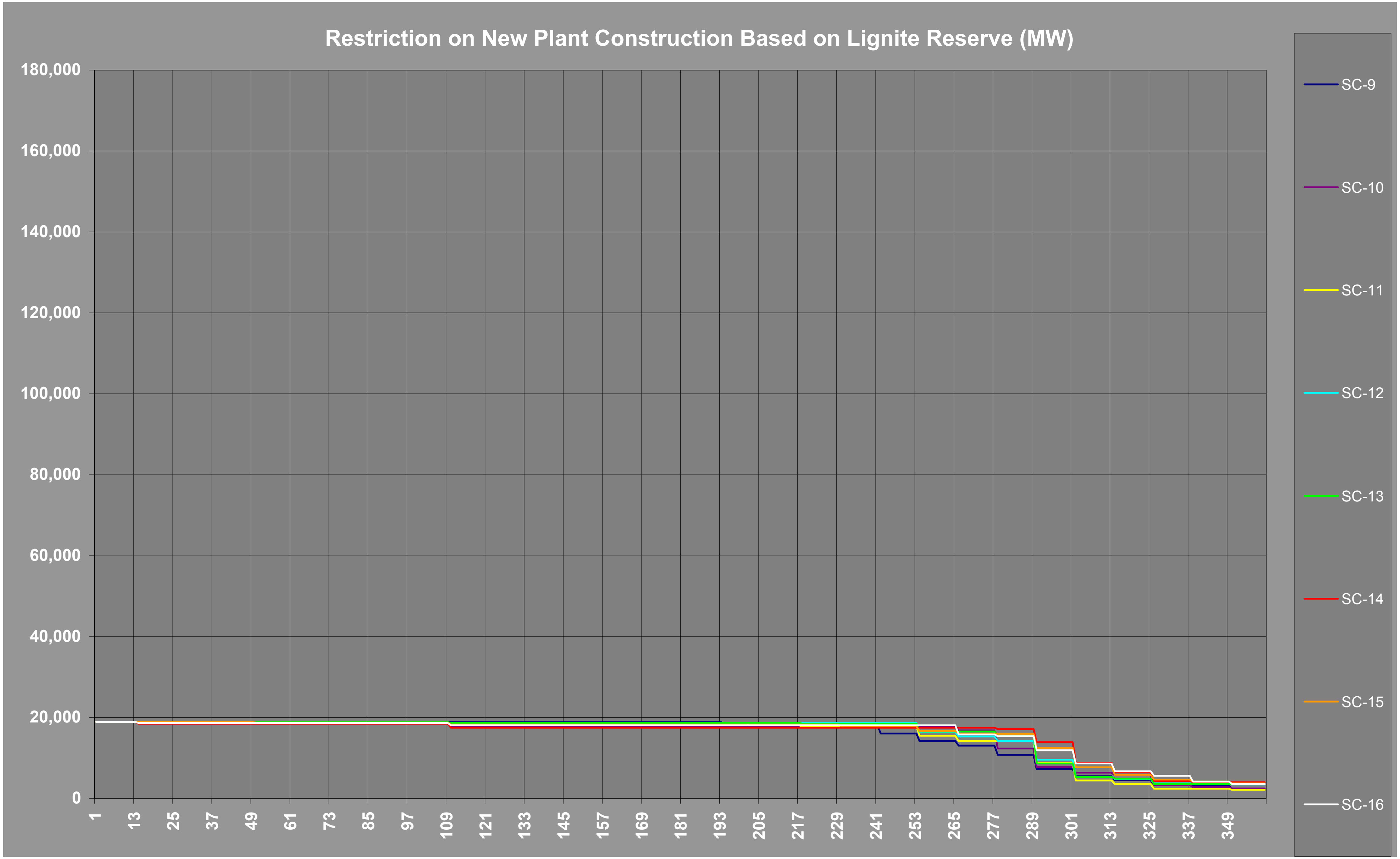

Restriction on New Plant Construction Based on Lignite Reserve (MW)
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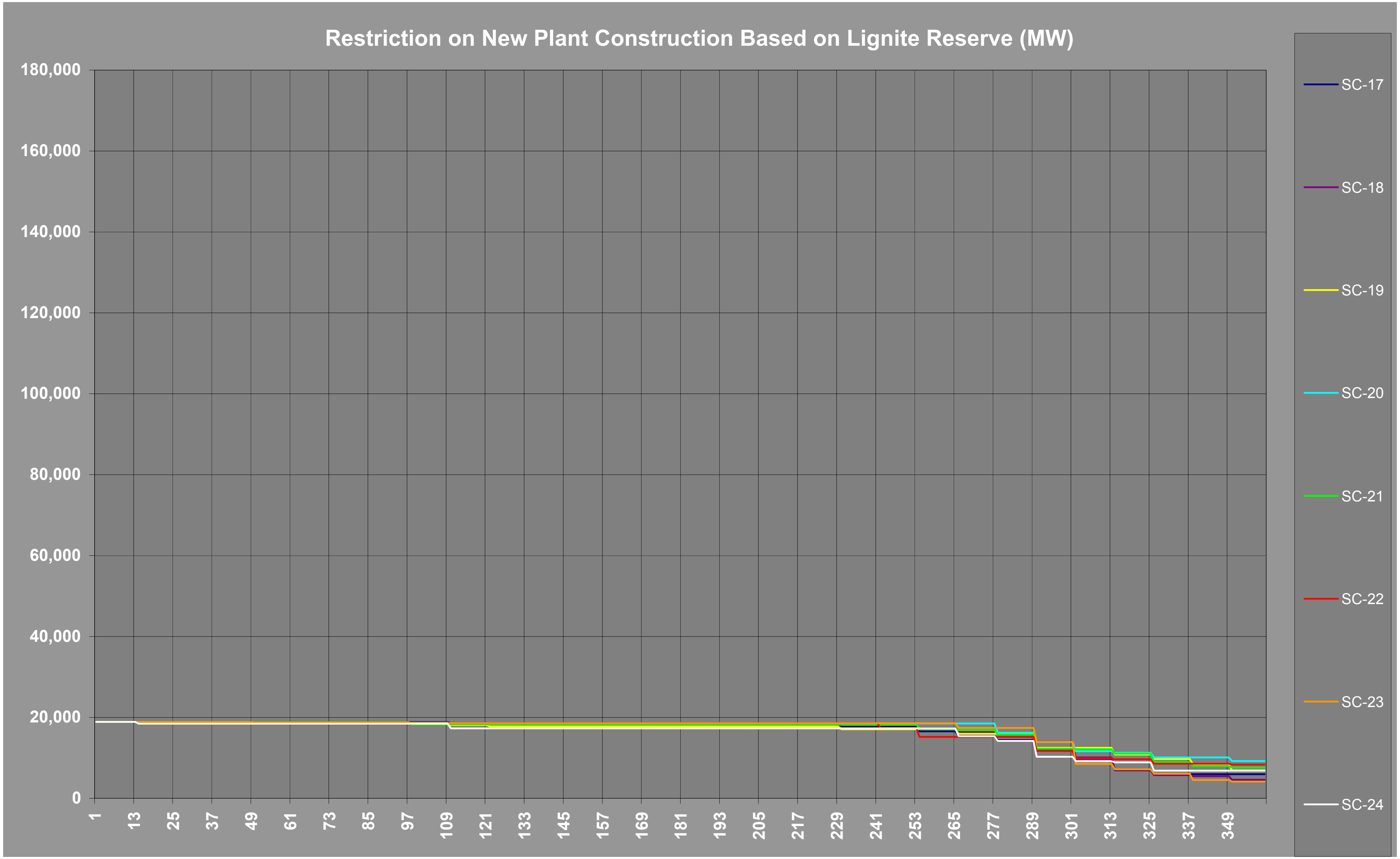
Restriction on New Plant Construction Based on Lignite Reserve (MW)
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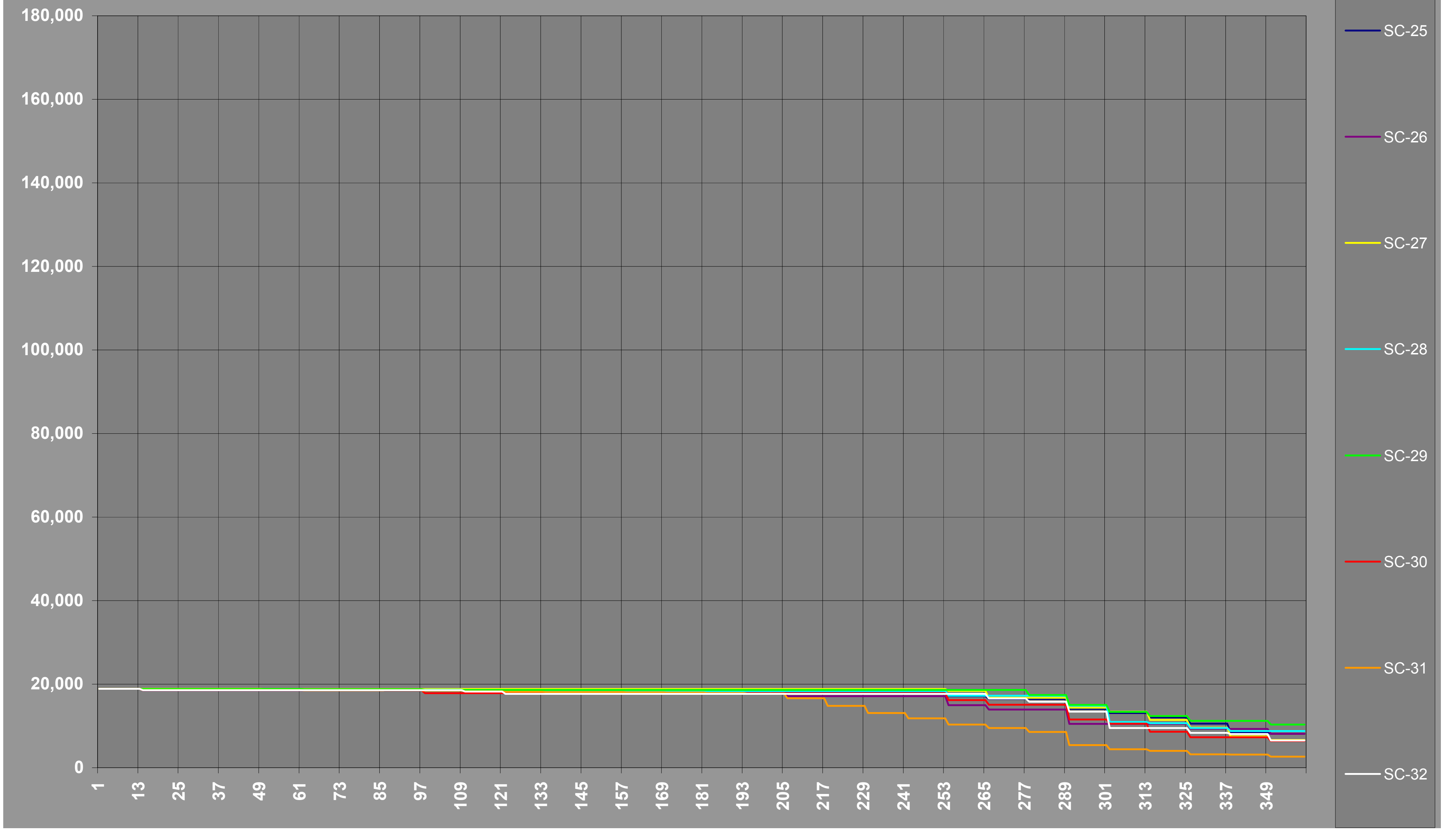
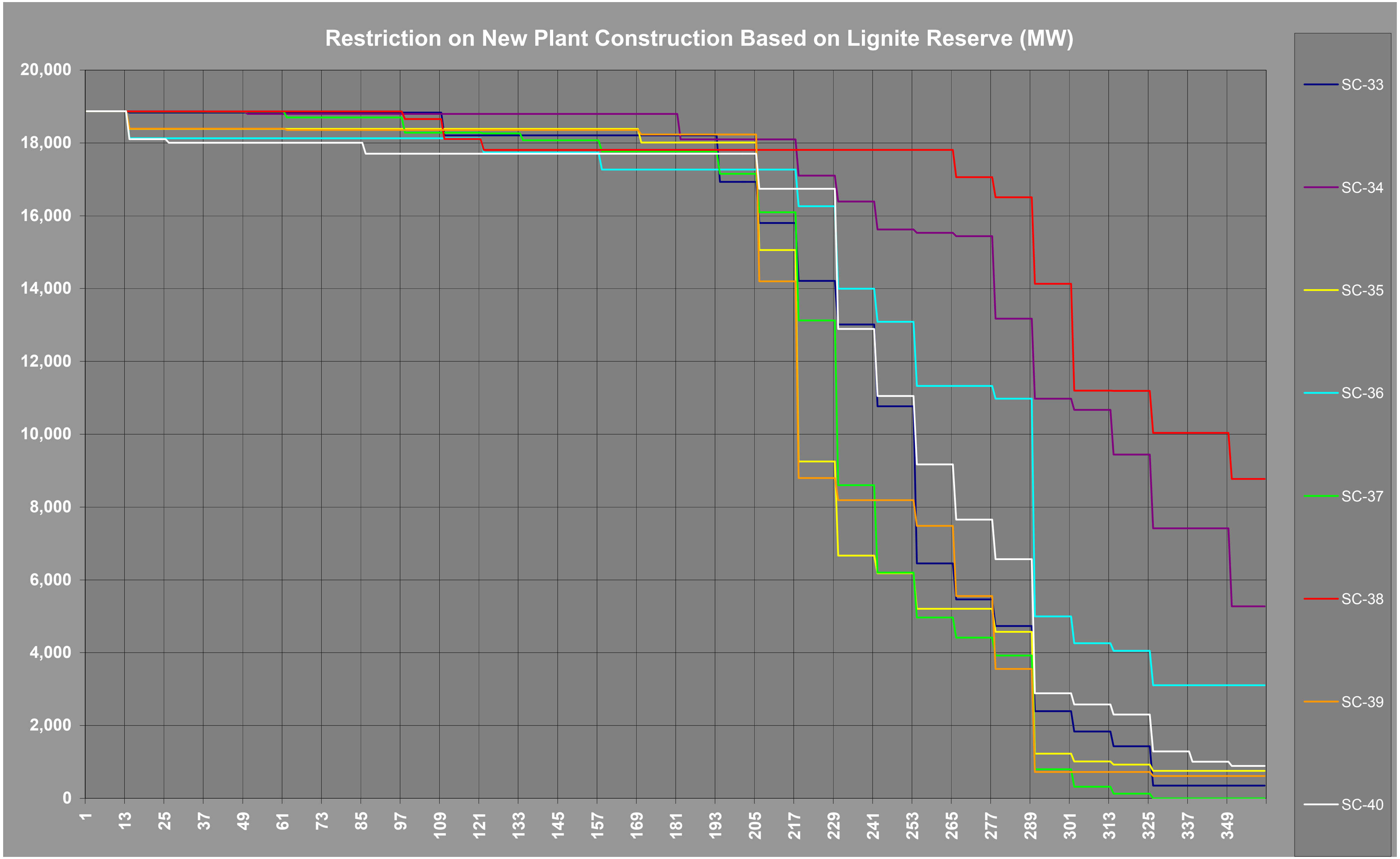
Restriction on New Plant Construction Based on Lignite Reserve (MW)





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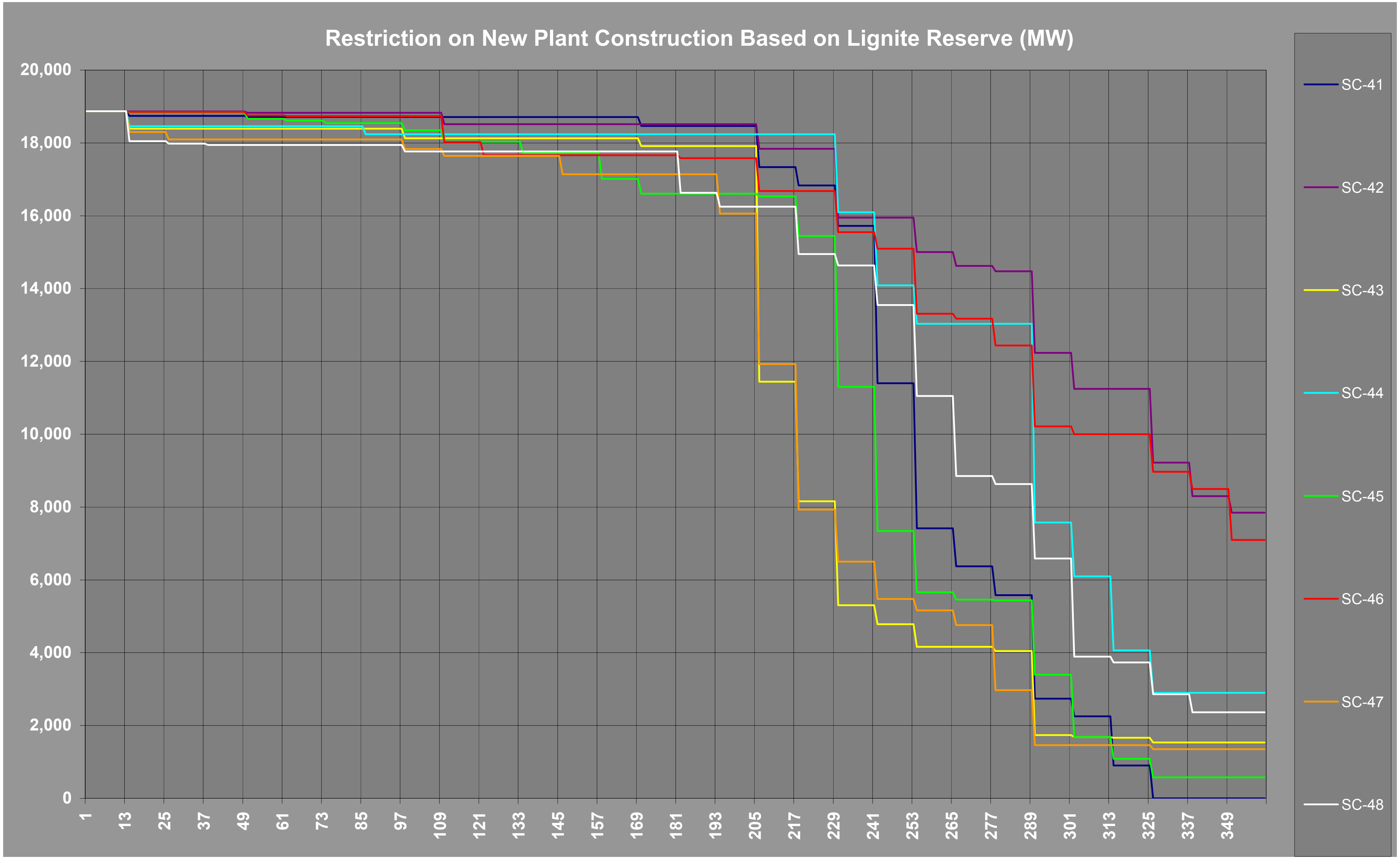

Restriction on New Plant Construction Based on Lignite Reserve (MW)
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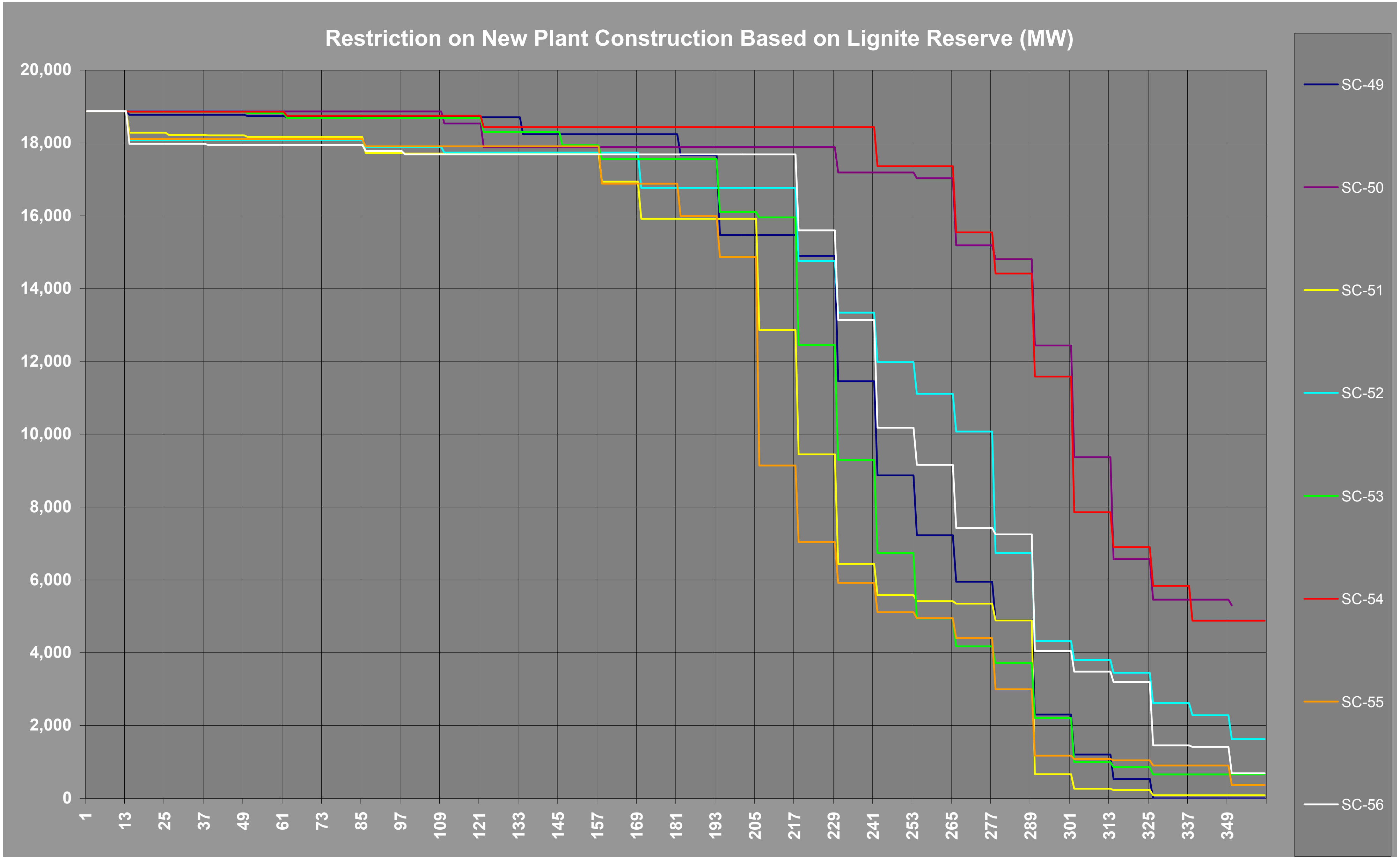
Restriction on New Plant Construction Based on Lignite Reserve (MW)
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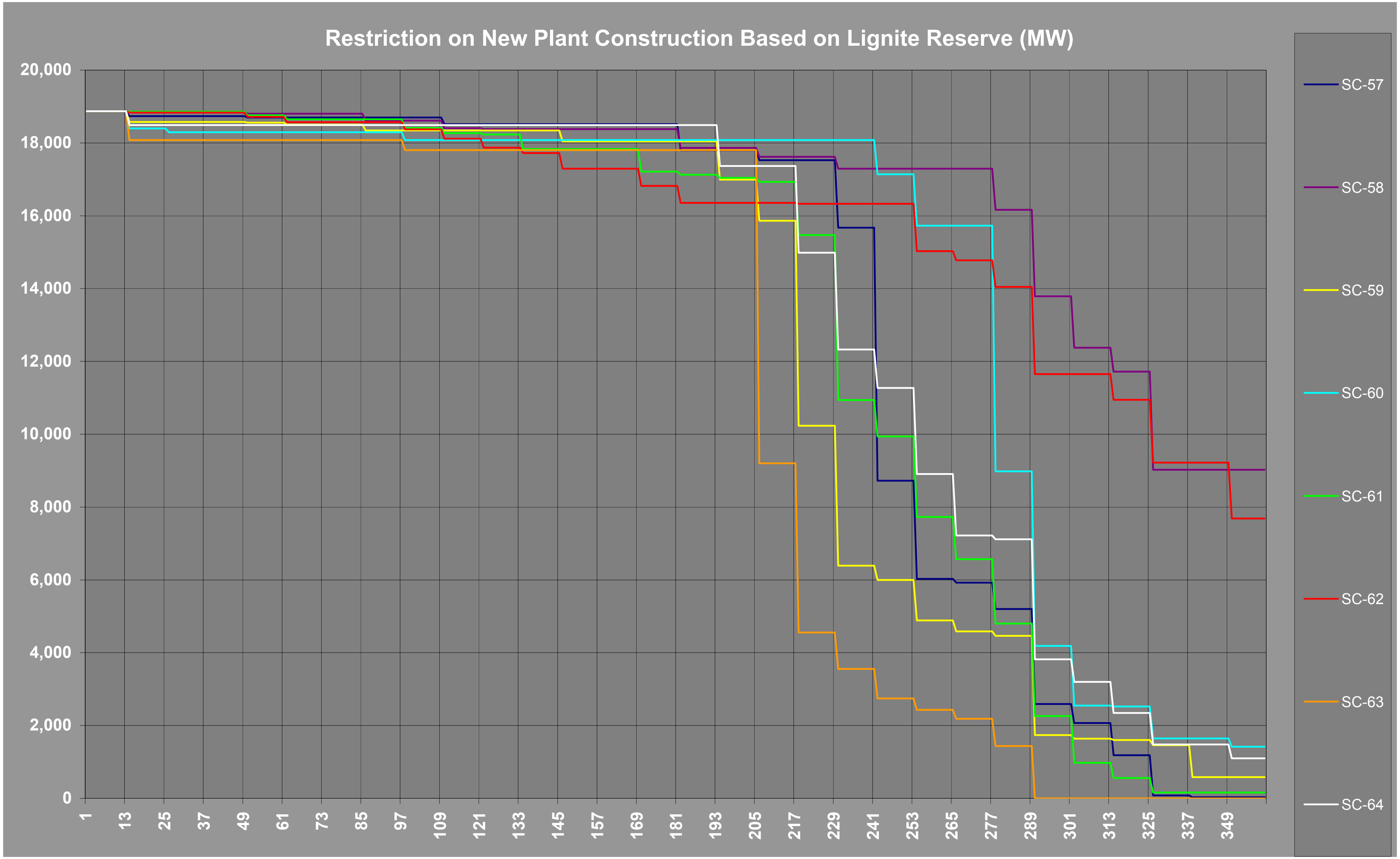

Restriction on New Plant Construction Based on Lignite Reserve (MW)
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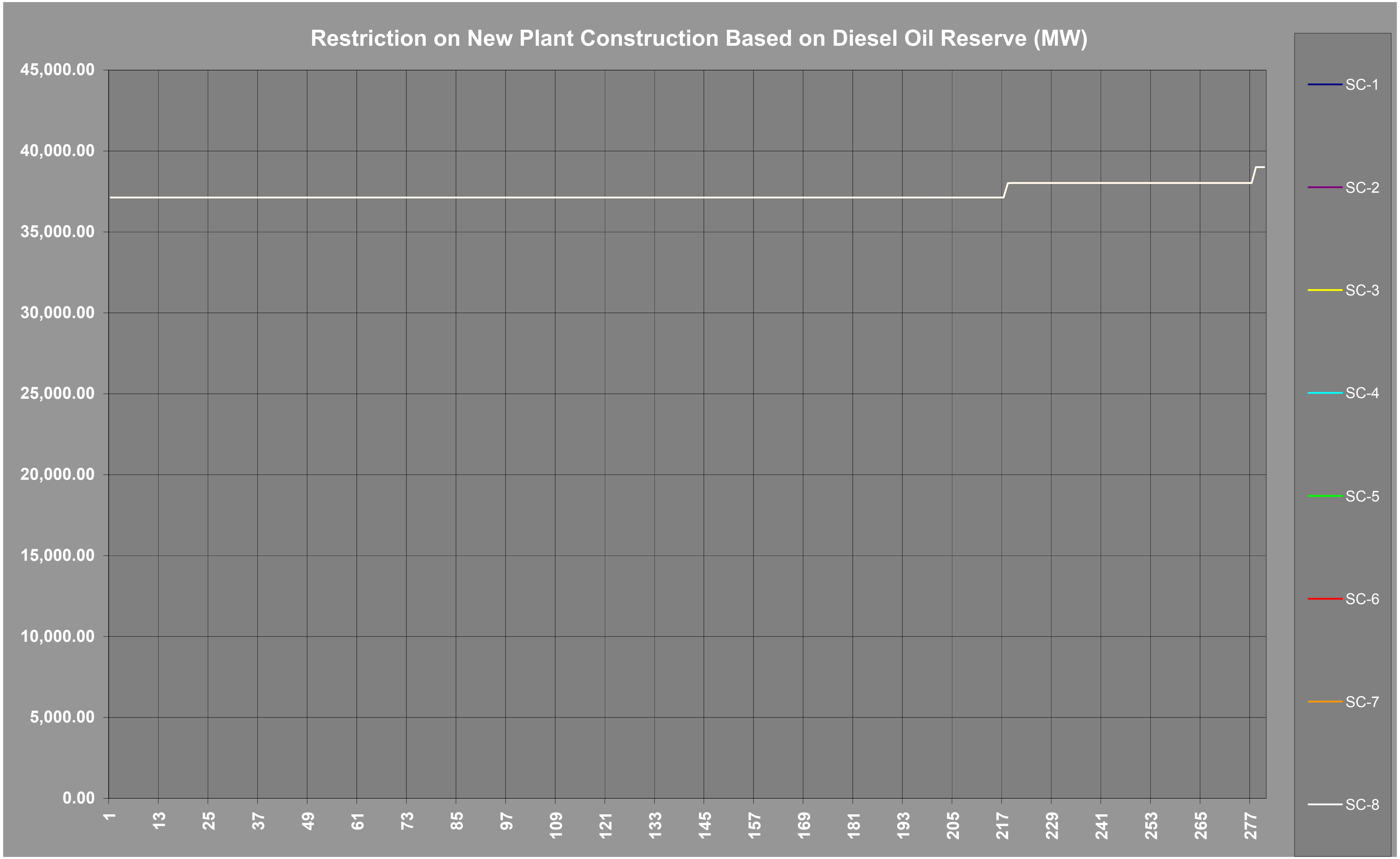
Restriction on New Plant Construction Based on Diesel Oil Reserve (MW)
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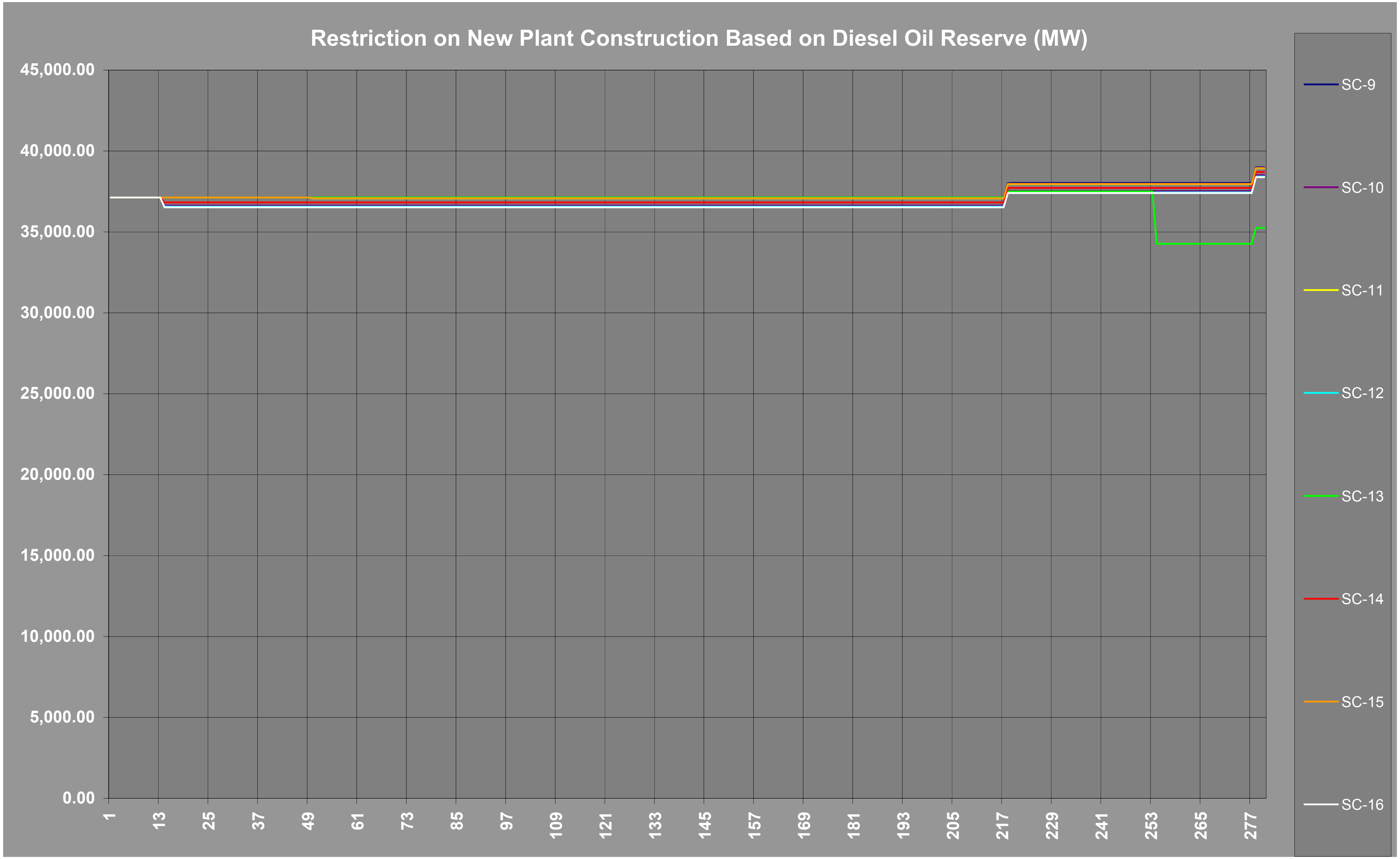
Restriction on New Plant Construction Based on Diesel Oil Reserve (MW)
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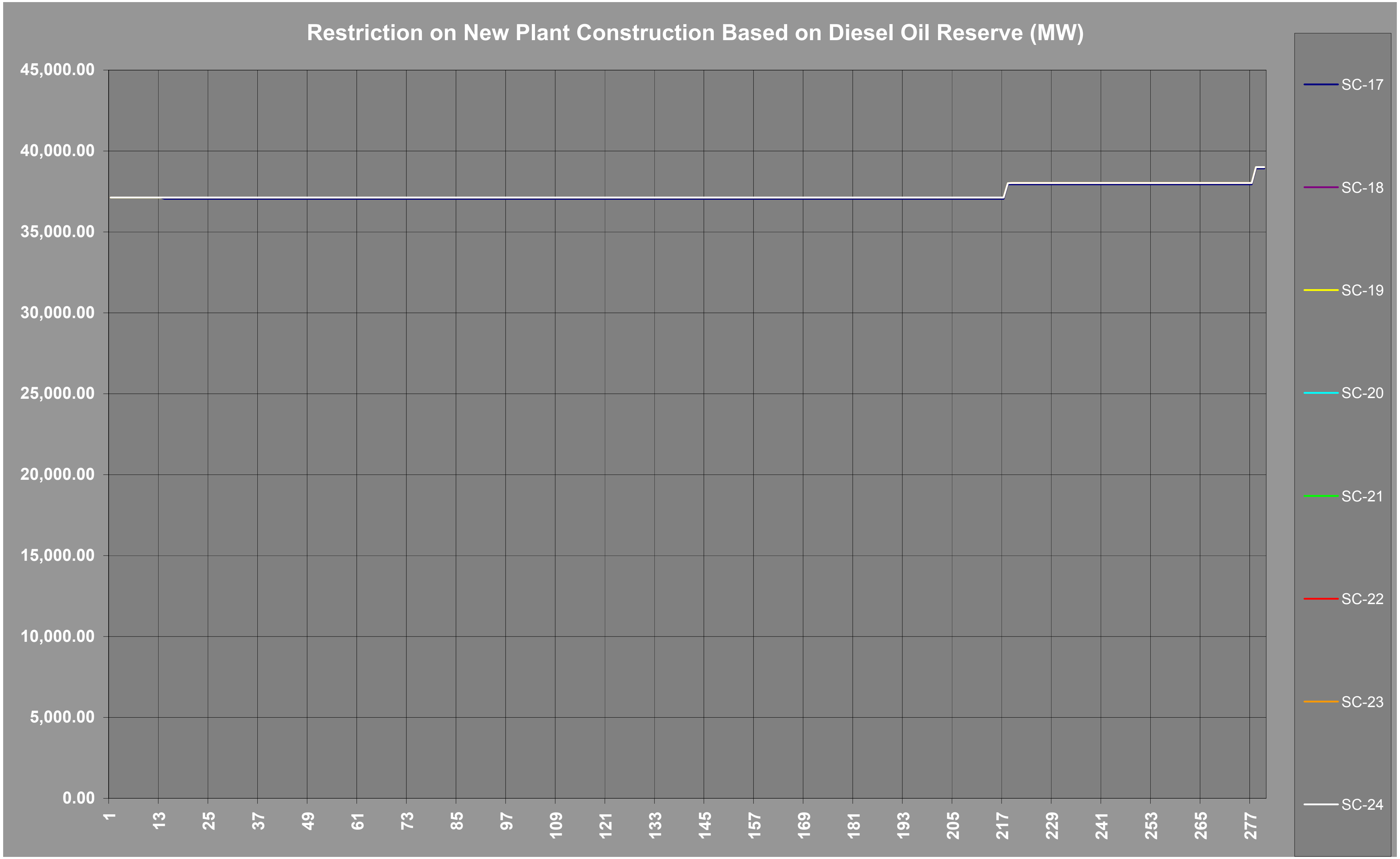

Restriction on New Plant Construction Based on Diesel Oil Reserve (MW)
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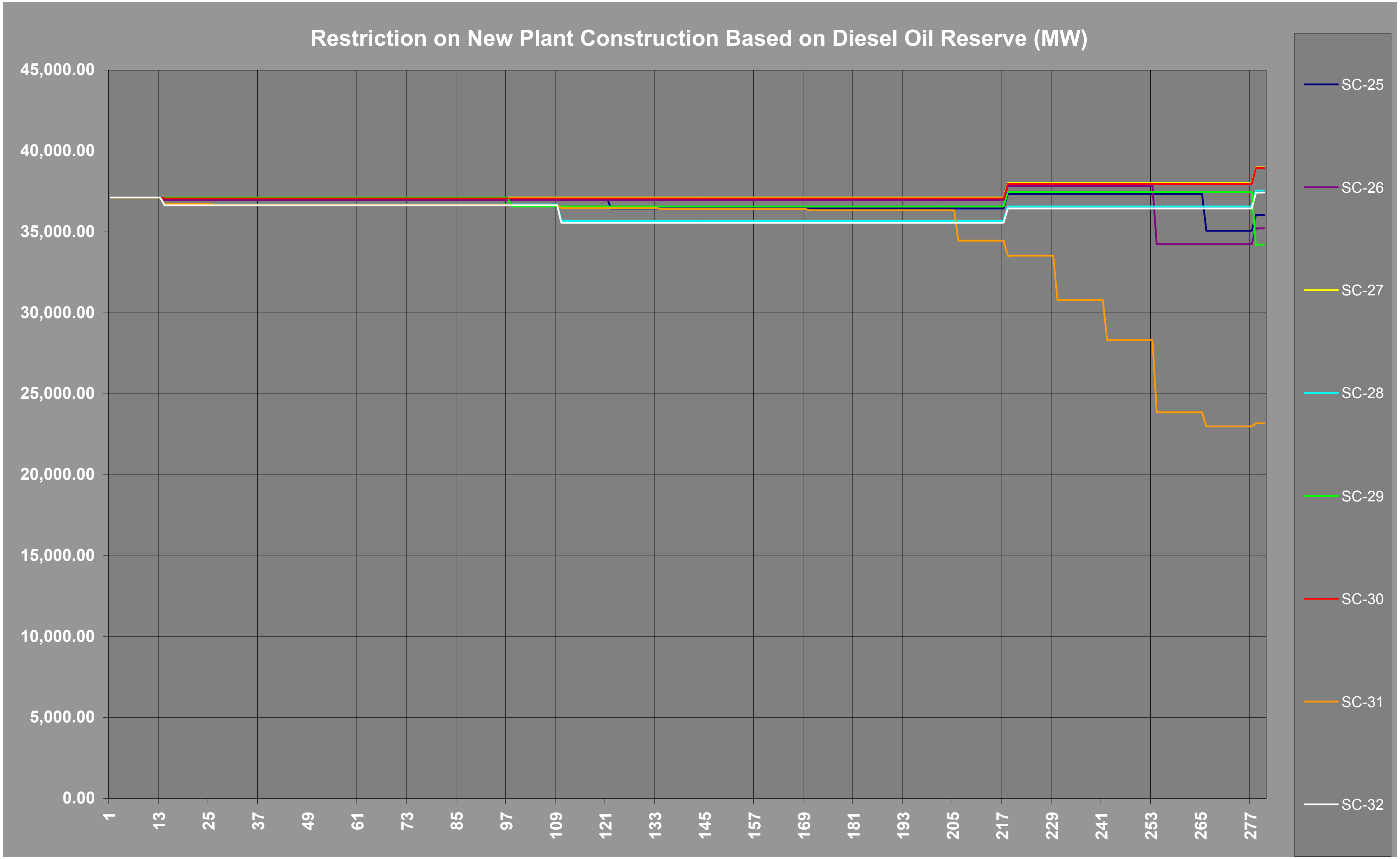
Restriction on New Plant Construction Based on Diesel Oil Reserve (MW)
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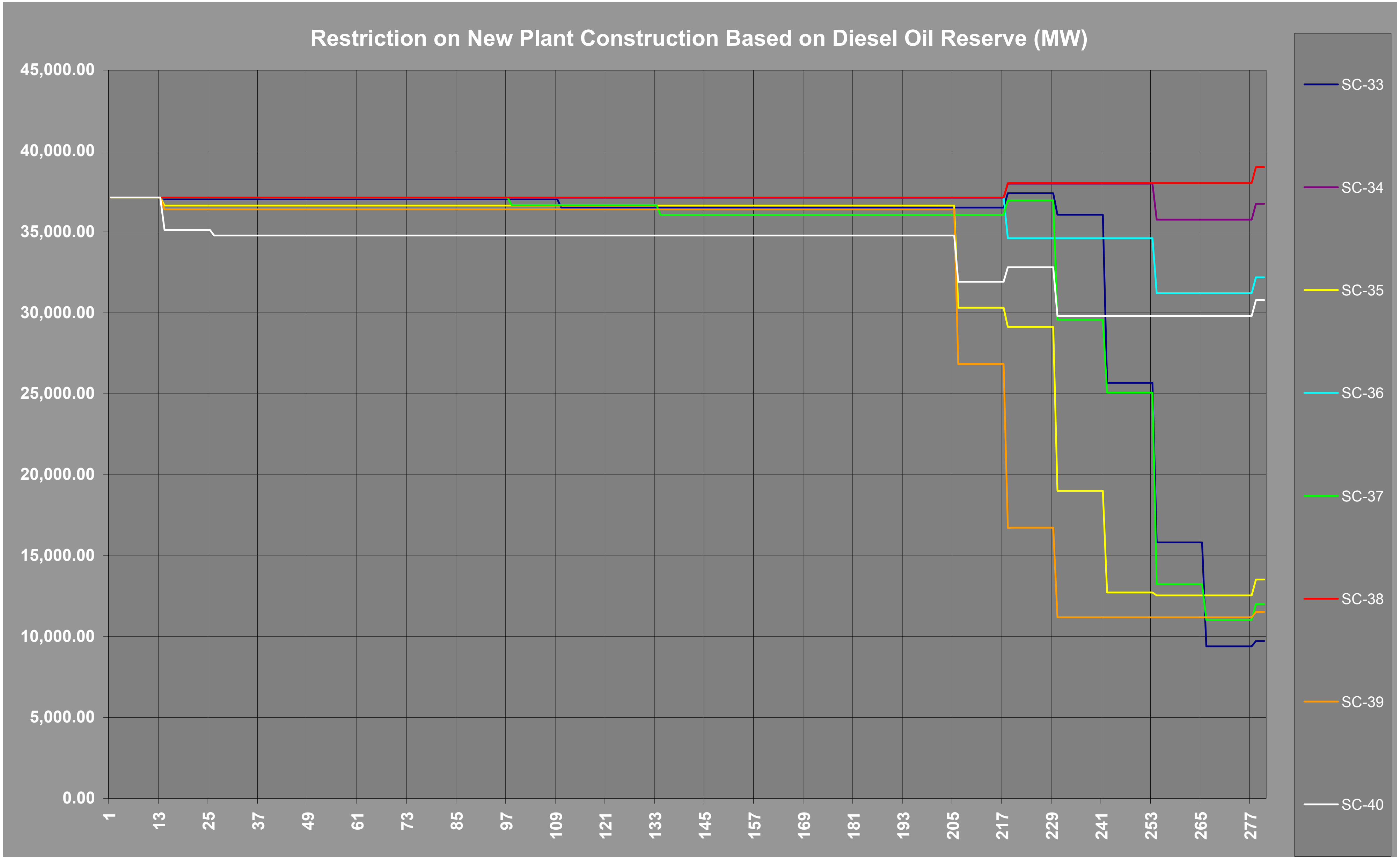
Restriction on New Plant Construction Based on Diesel Oil Reserve (MW)
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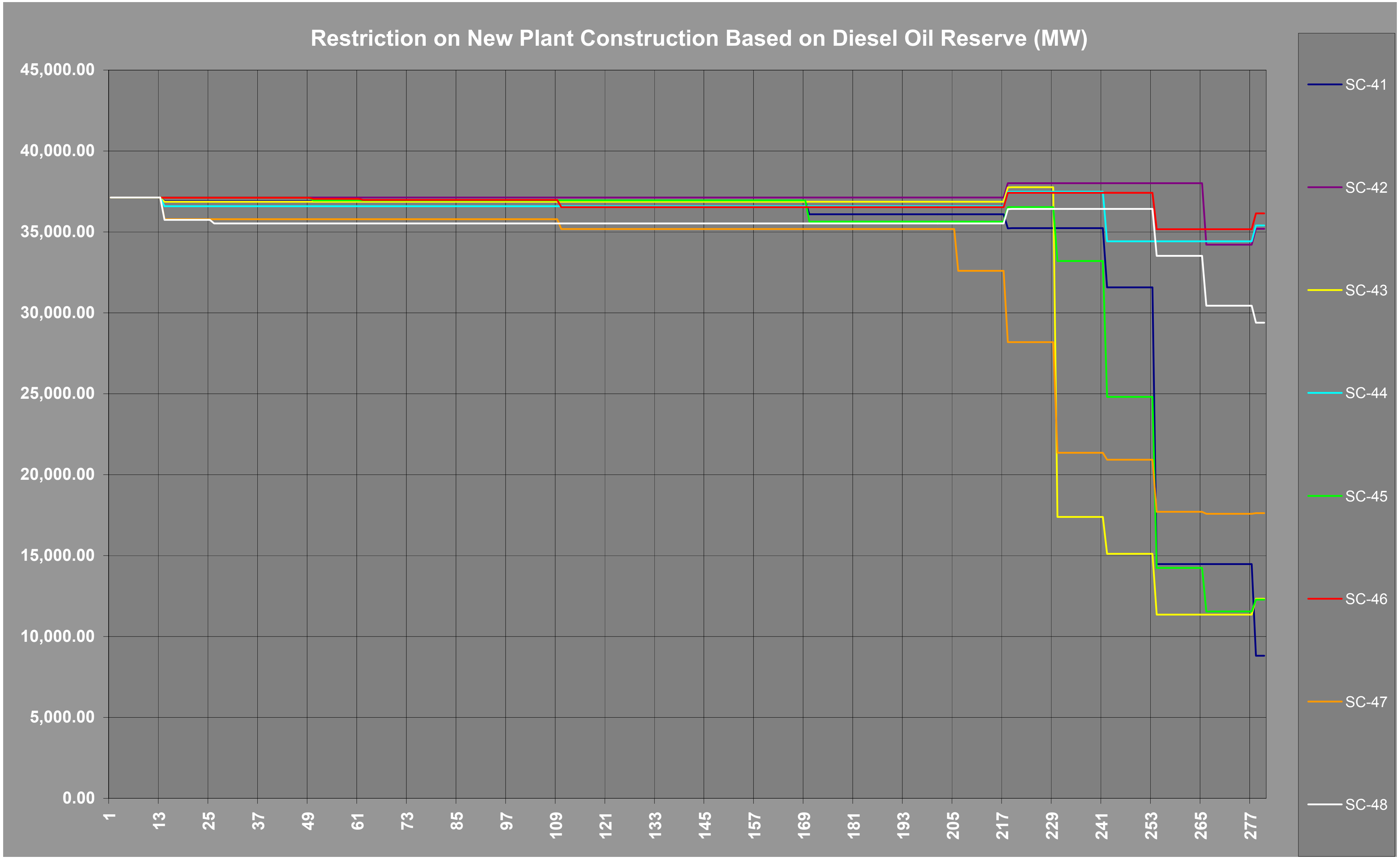
Restriction on New Plant Construction Based on Diesel Oil Reserve (MW)
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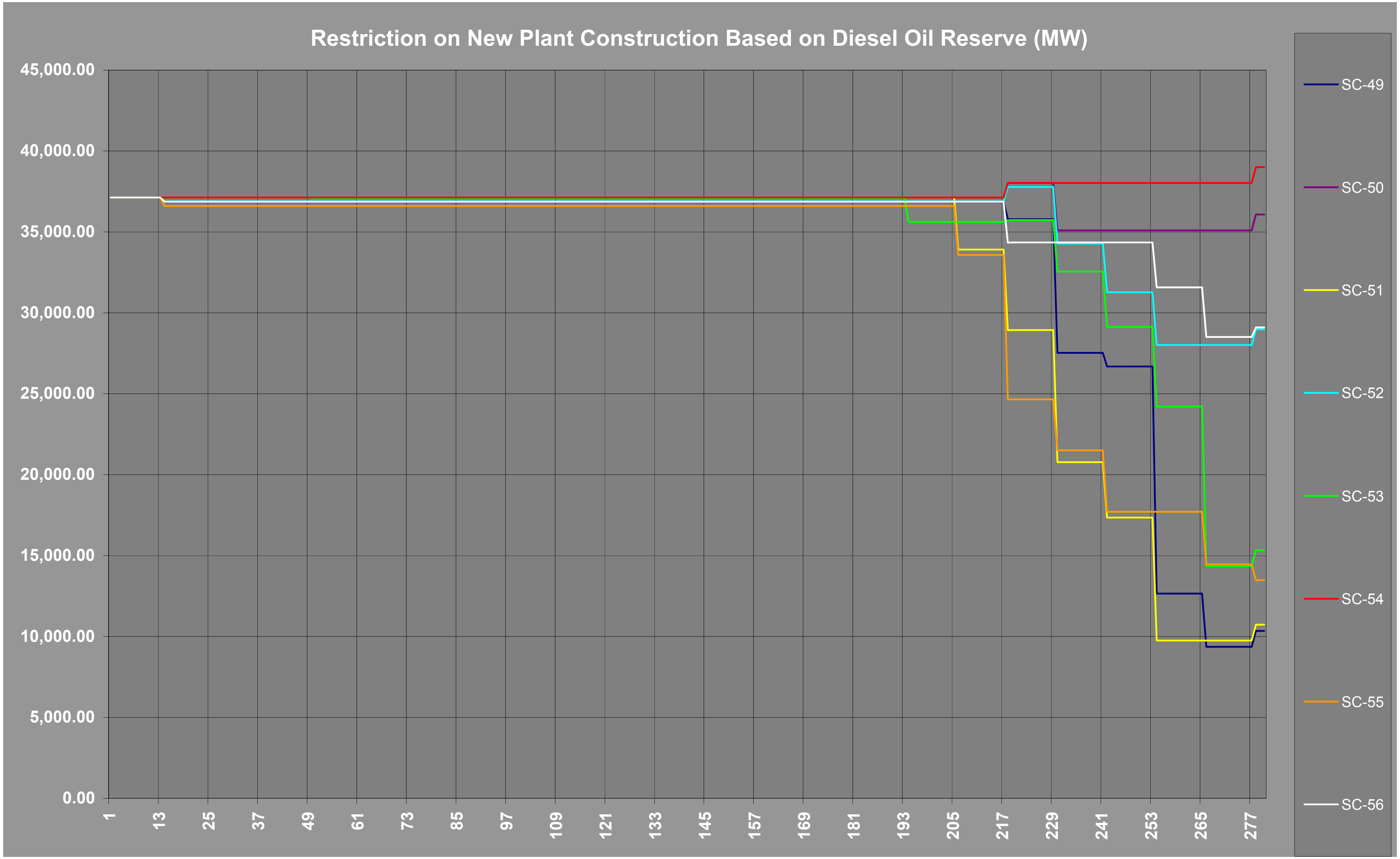
Restriction on New Plant Construction Based on Diesel Oil Reserve (MW)
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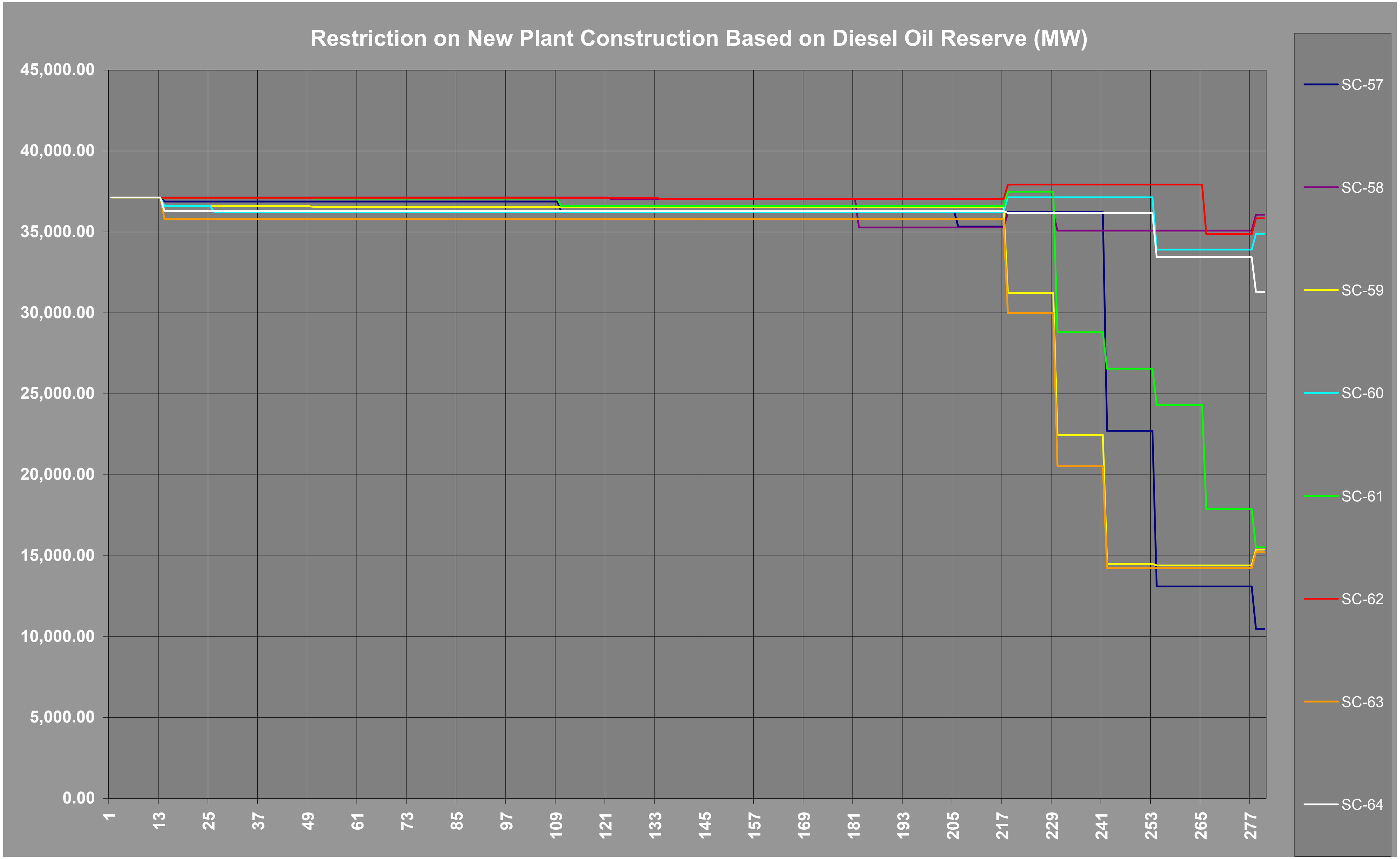
Restriction on New Plant Construction Based on Diesel Oil Reserve (MW)
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Restriction on New Plant Construction Based on Geothermal Reserve (MW)
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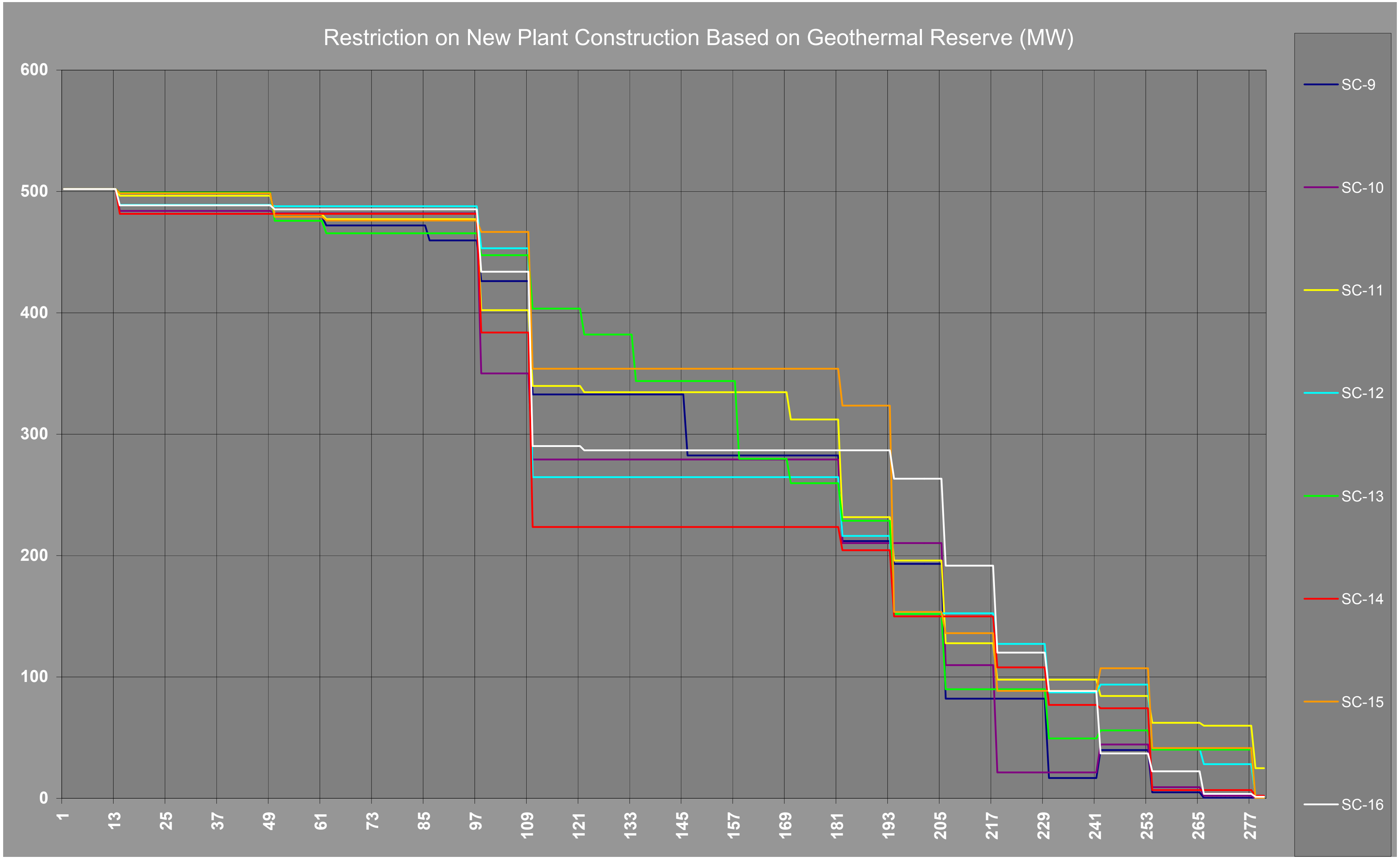
Restriction on New Plant Construction Based on Geothermal Reserve (MW)
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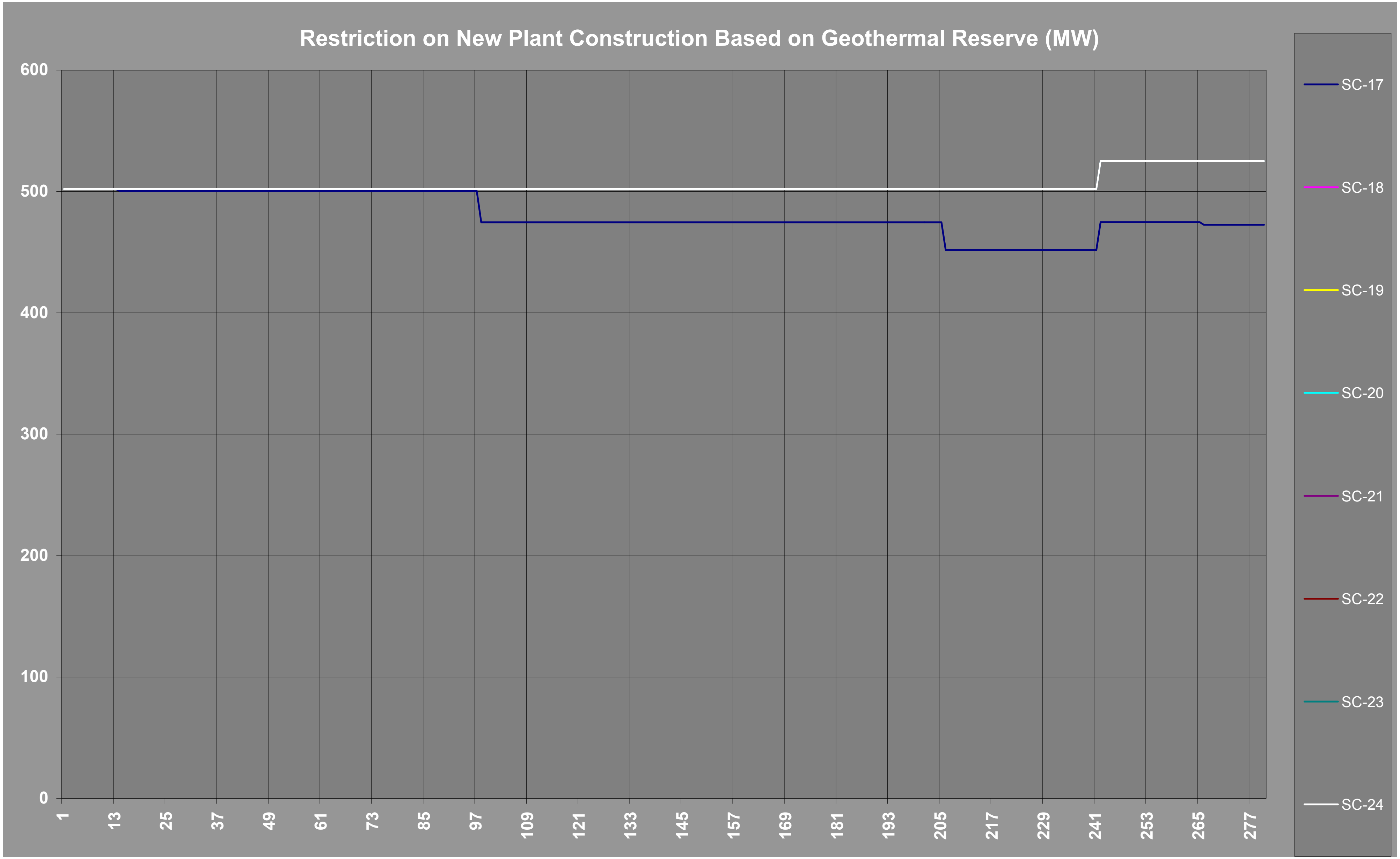
Restriction on New Plant Construction Based on Geothermal Reserve (MW)
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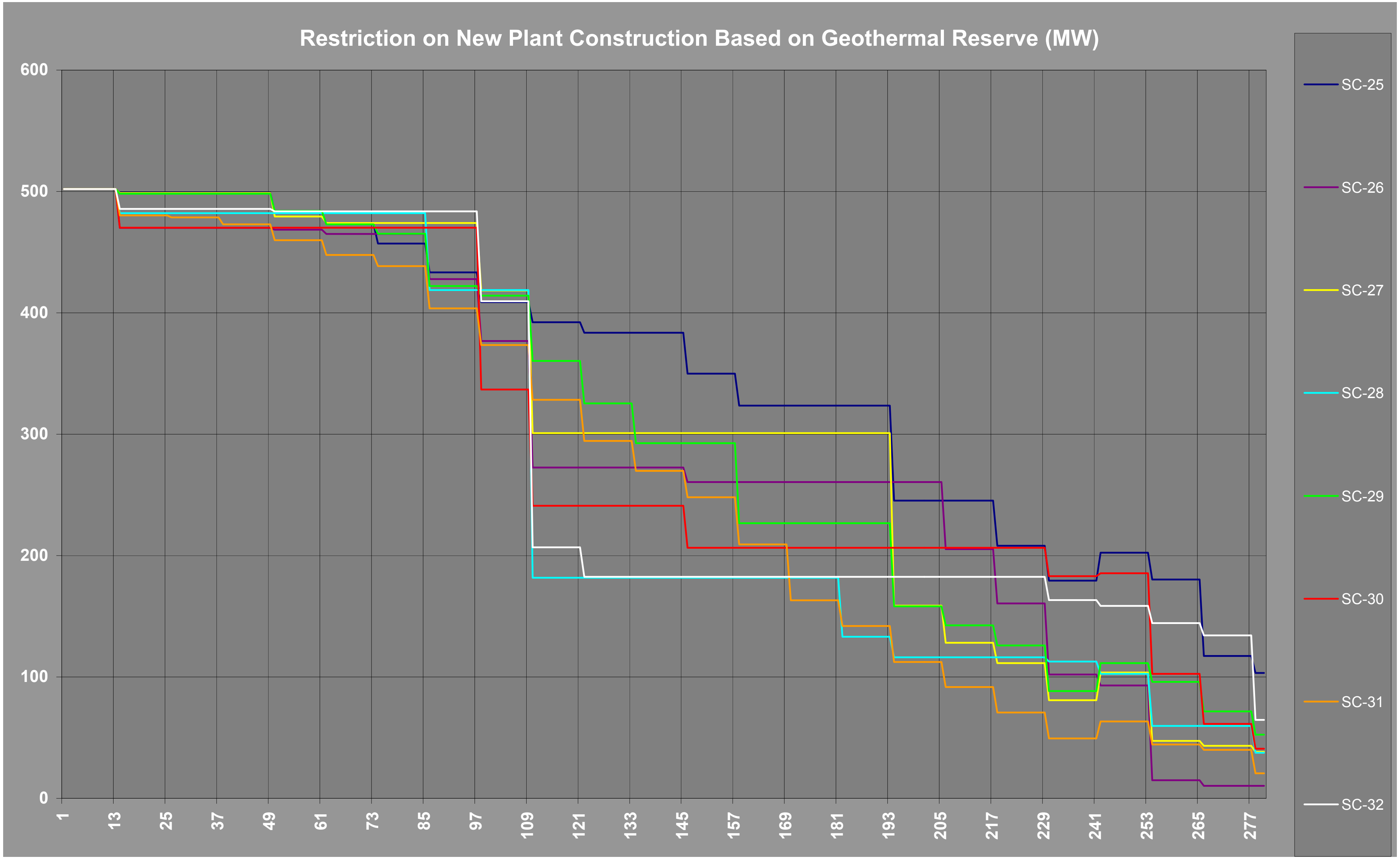

Restriction on New Plant Construction Based on Geothermal Reserve (MW)
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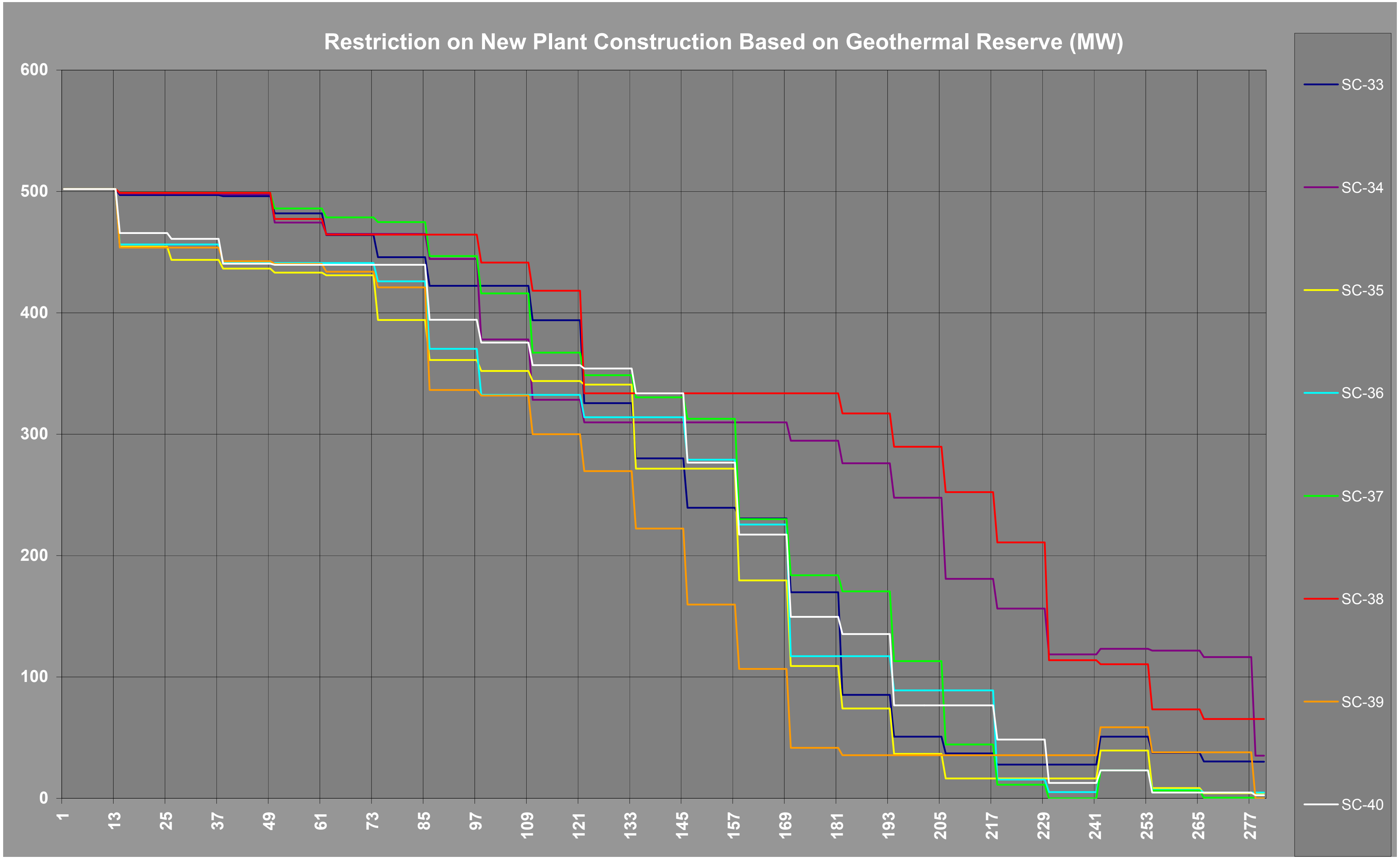
Restriction on New Plant Construction Based on Geothermal Reserve (MW)
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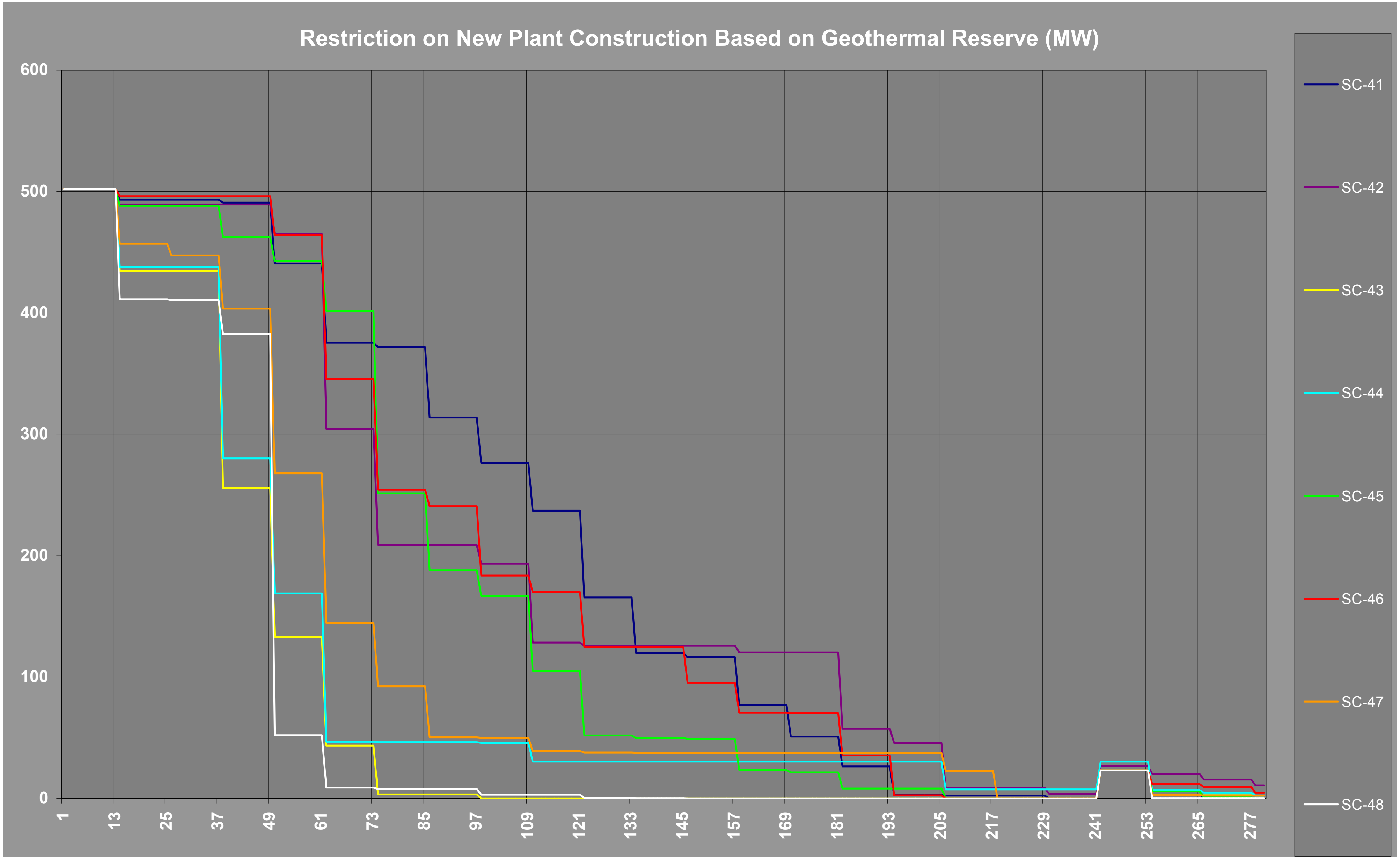

Restriction on New Plant Construction Based on Geothermal Reserve (MW)
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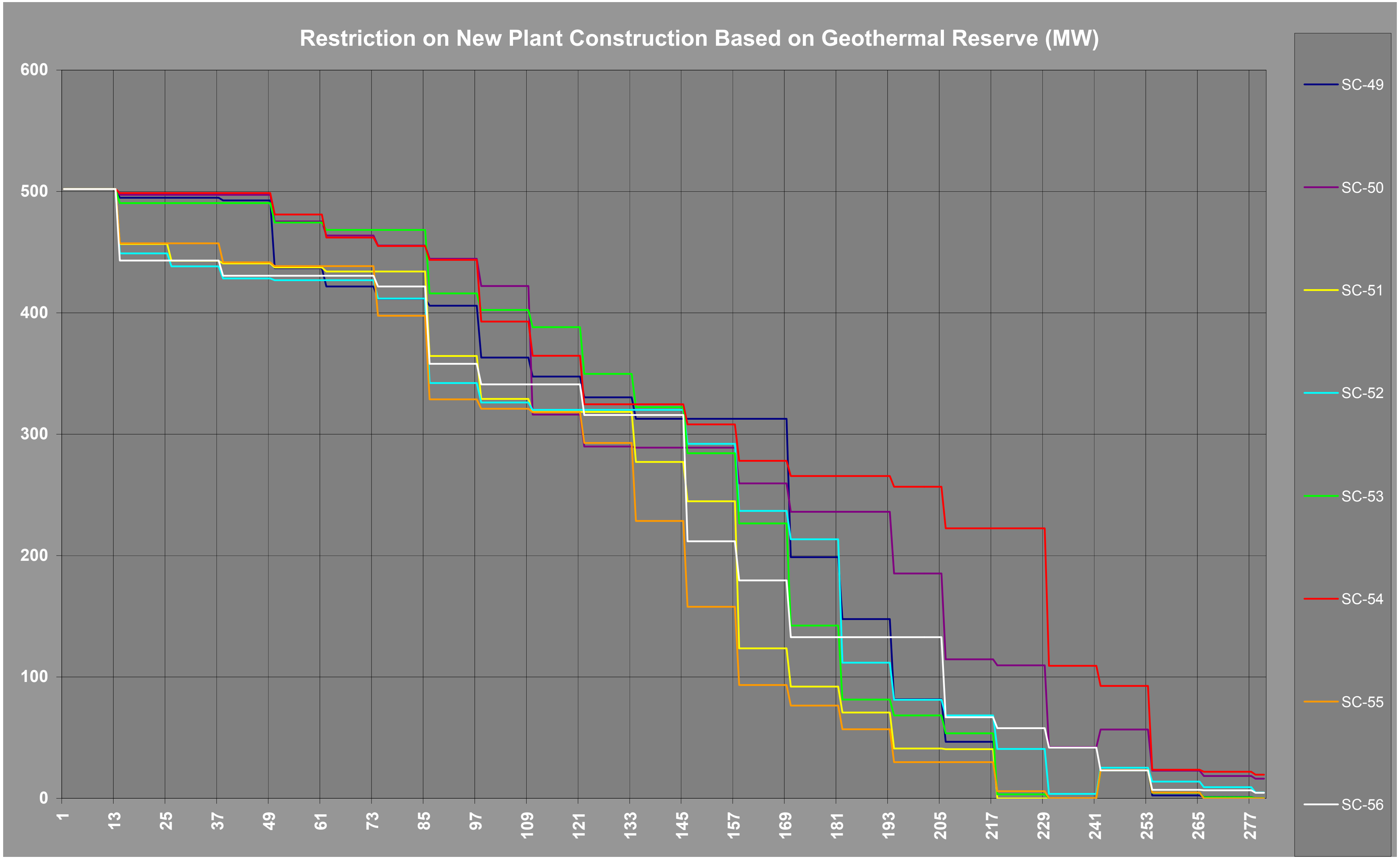

Restriction on New Plant Construction Based on Geothermal Reserve (MW)
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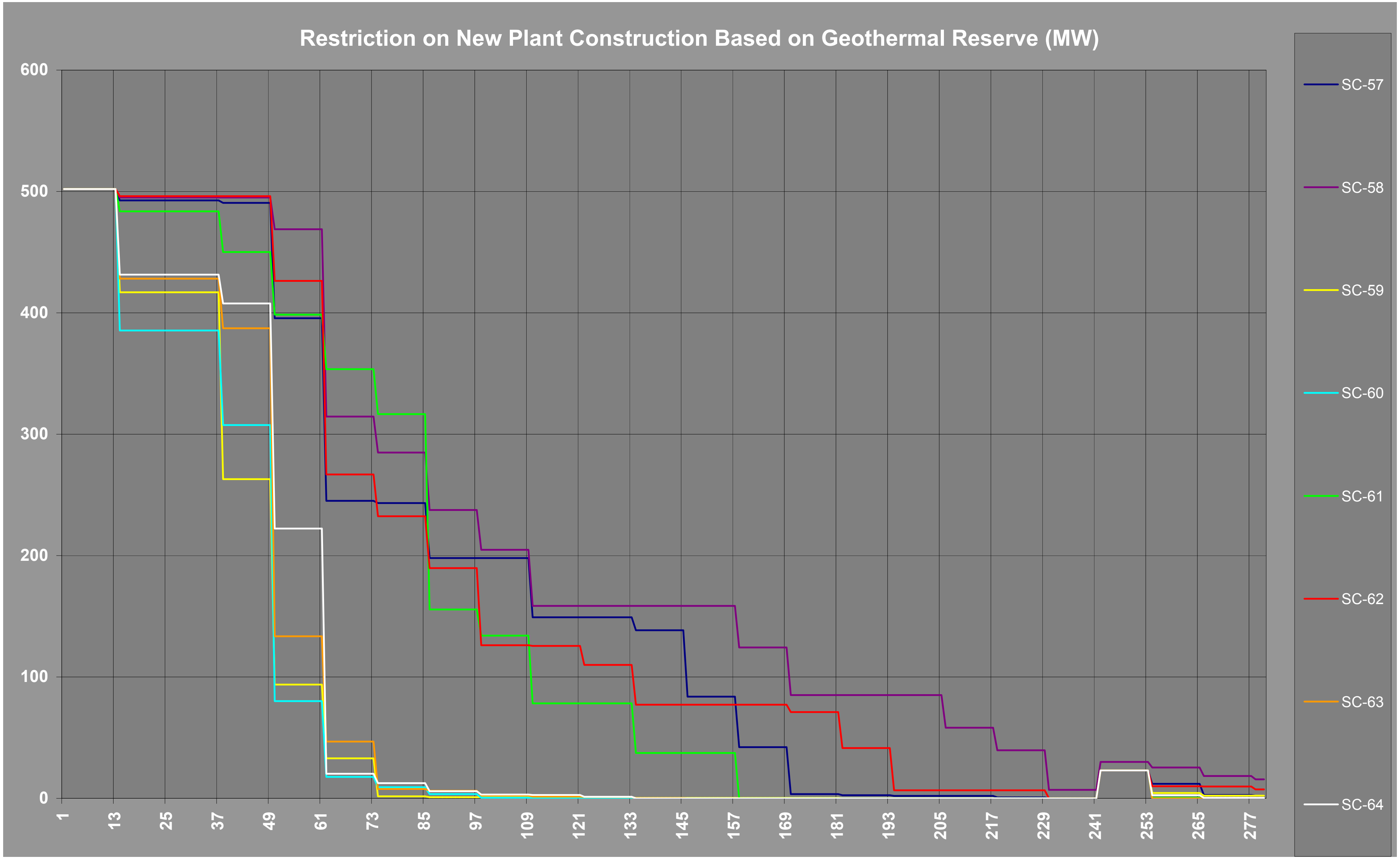
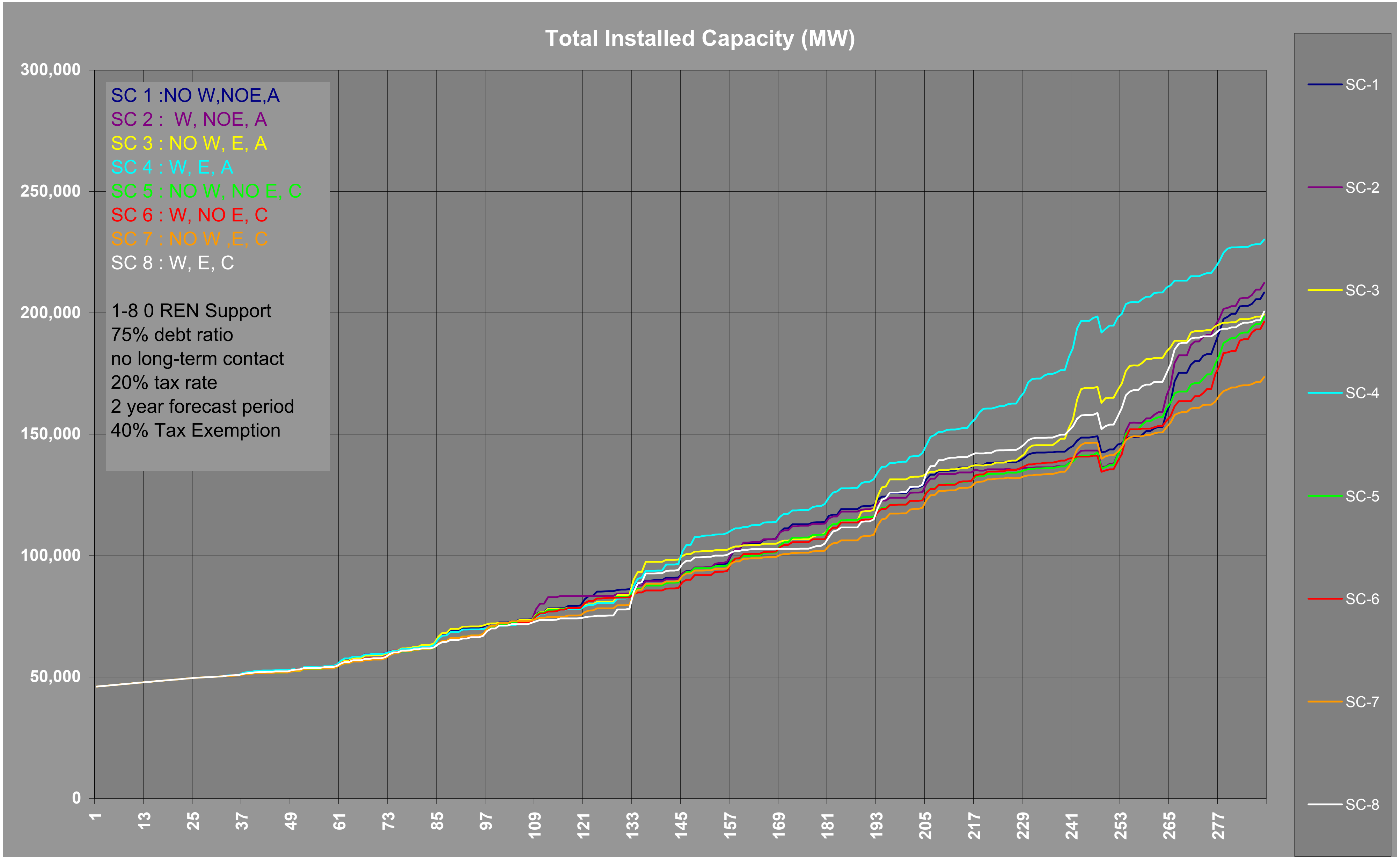
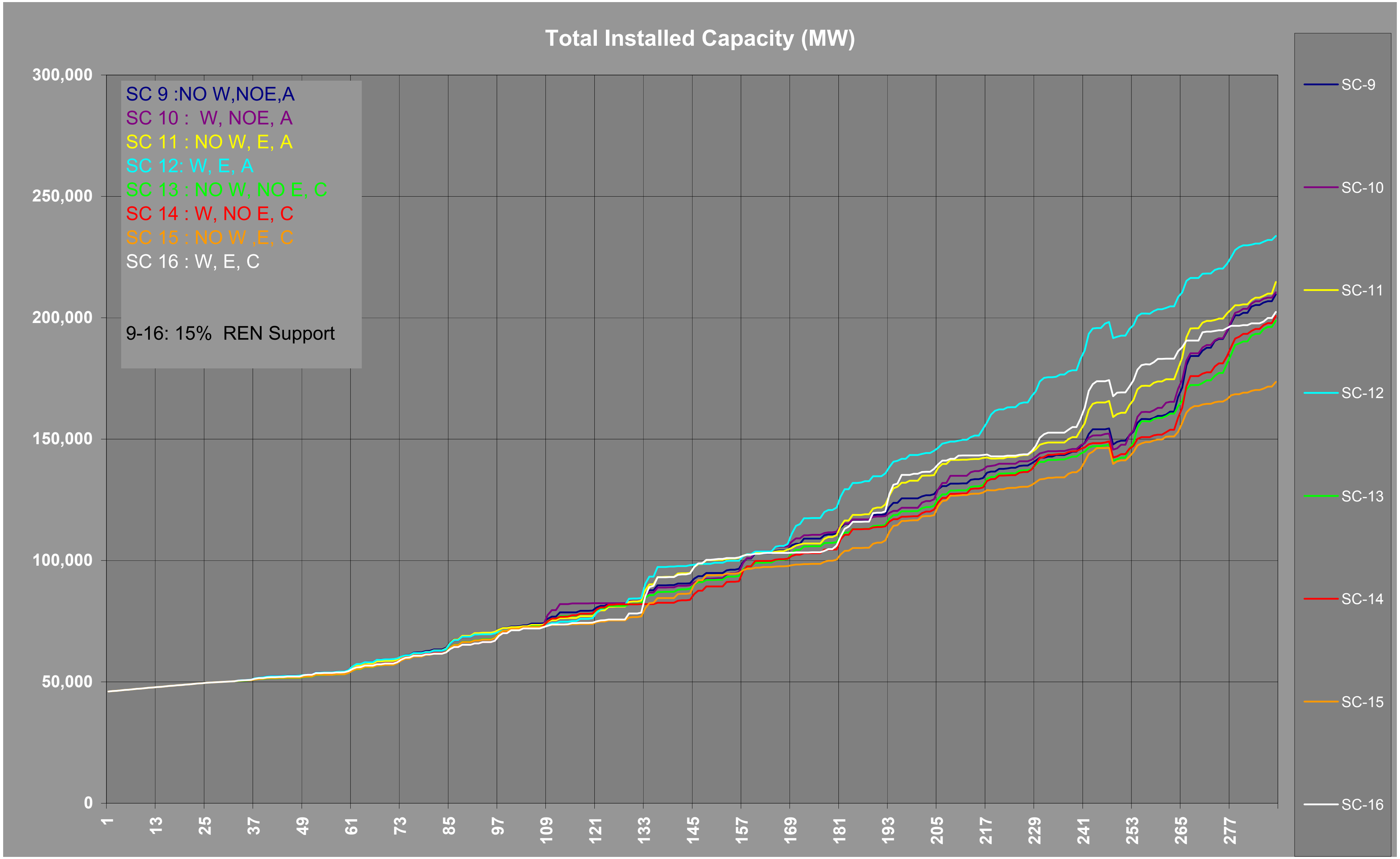
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-49
SC-50
SC-51
SC-52
SC-53
SC-54
SC-55
SC-56

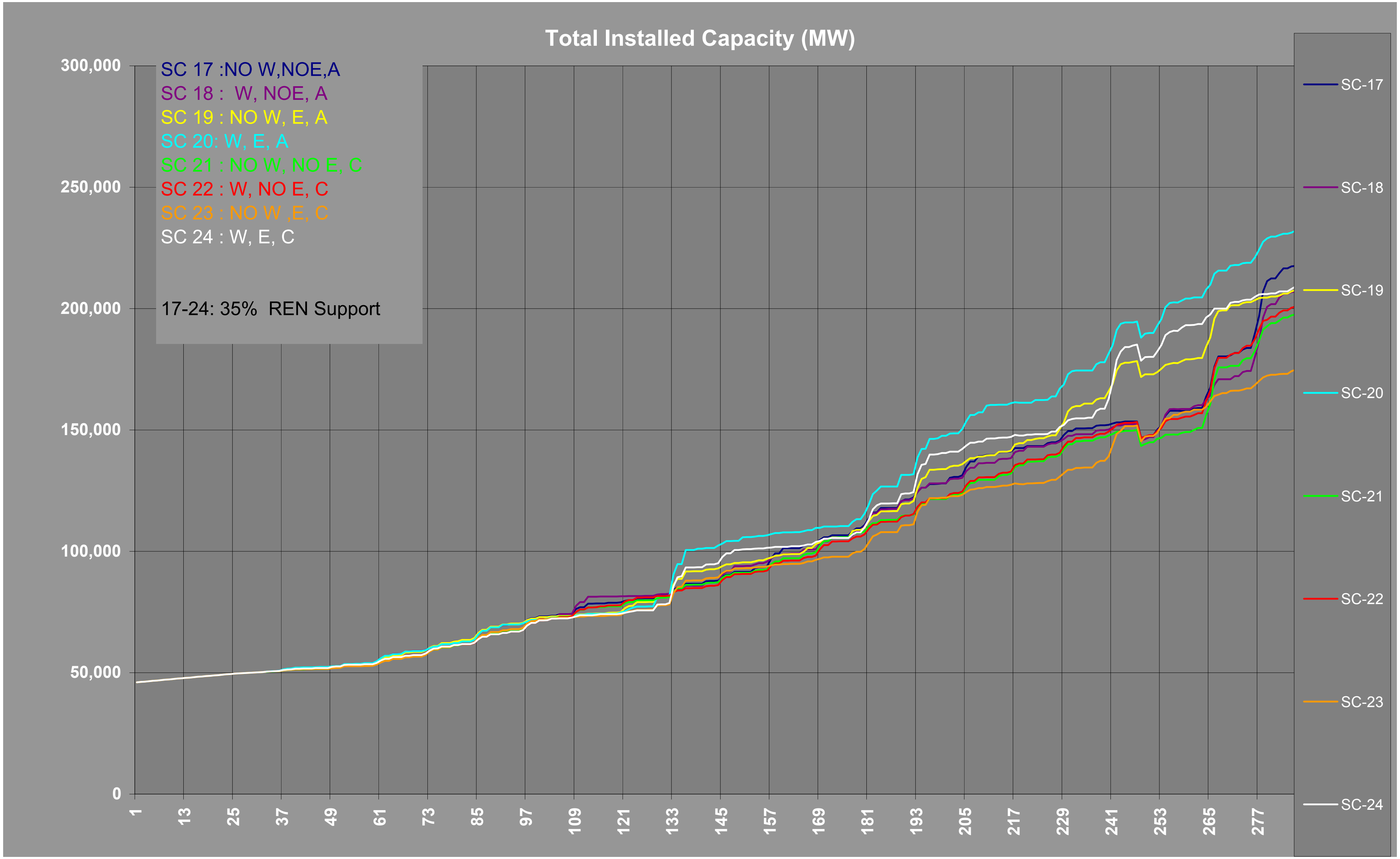

Restriction on New Plant Construction Based on Geothermal Reserve (MW)
600
500
400
300
200
100
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-57
SC-58
SC-59
SC-60
SC-61
SC-62
SC-63
SC-64



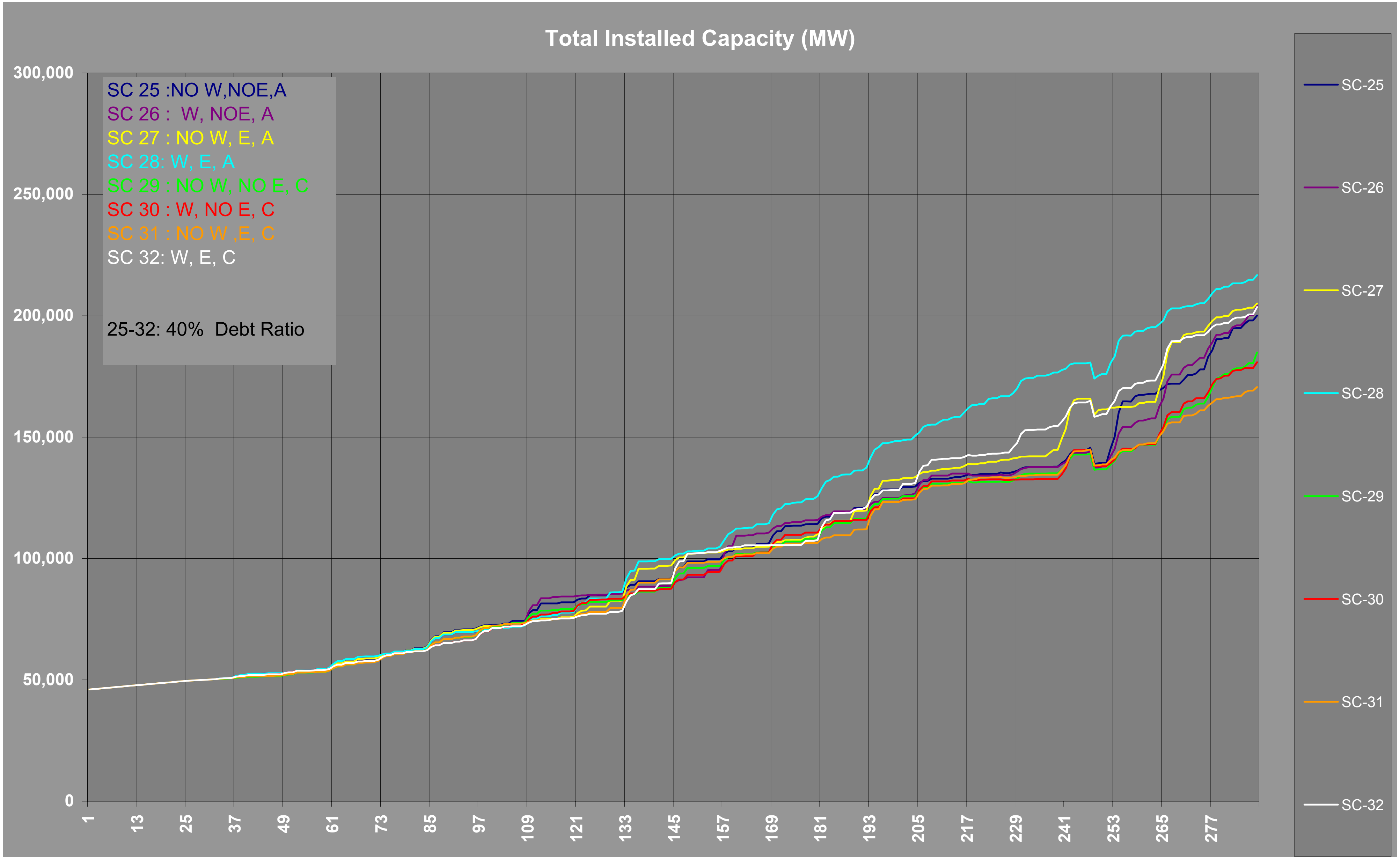
Total Installed Capacity (MW)
300,000
250,000
200,000
150,000
100,000
50,000
0
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



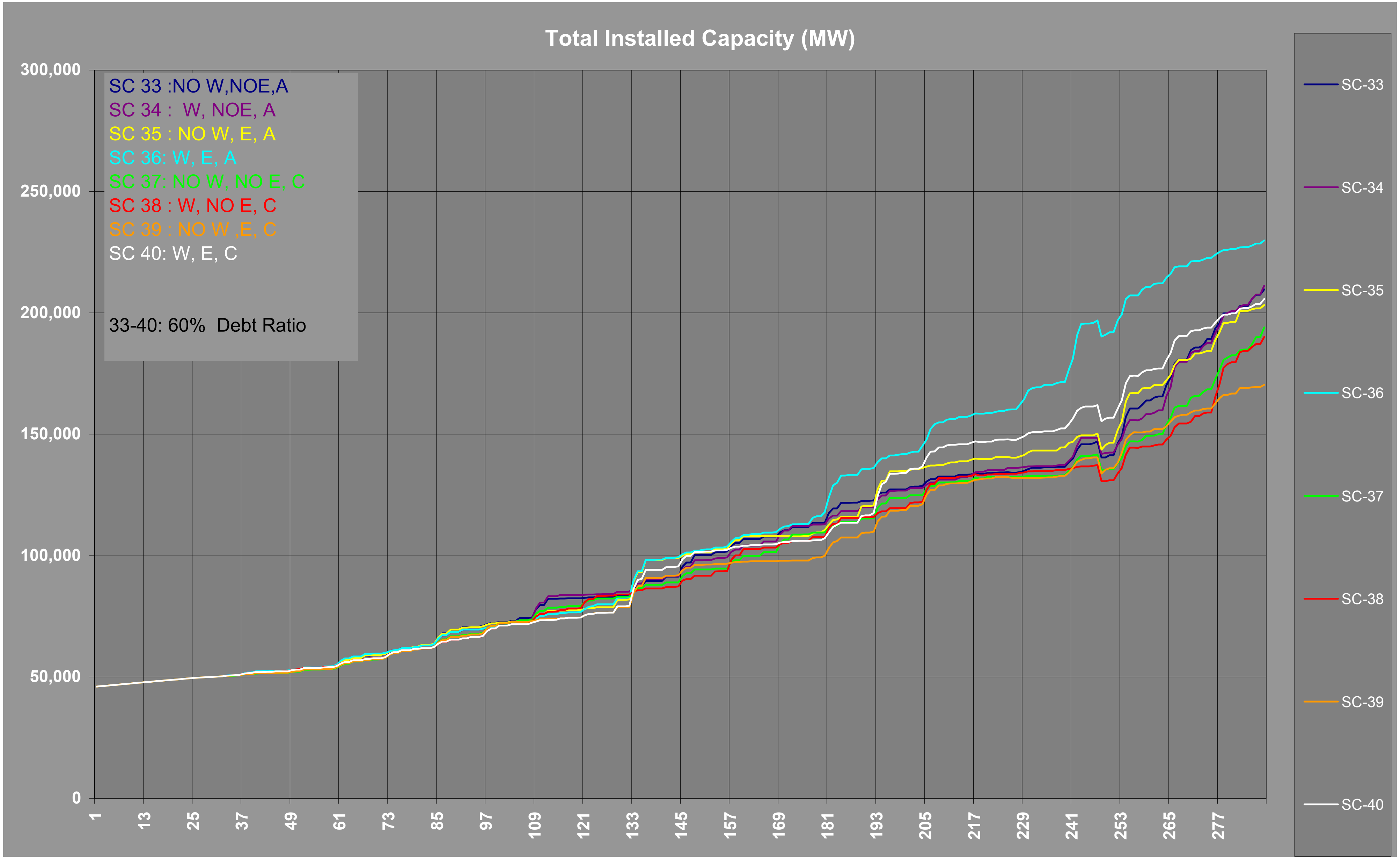
Total Installed Capacity (MW)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
300,000
250,000
200,000
150,000
100,000
50,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16

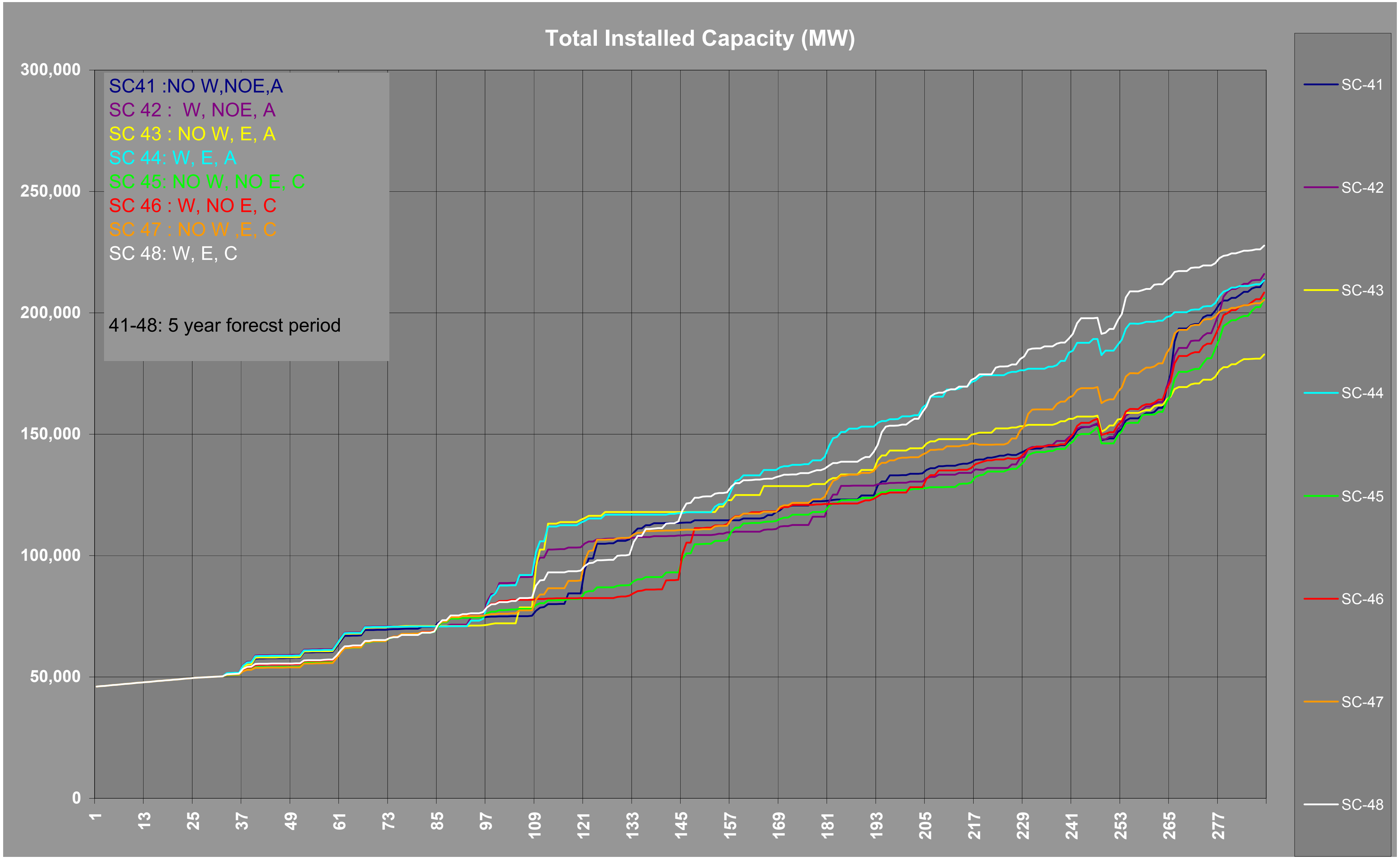


Total Installed Capacity (MW)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
300,000
250,000
200,000
150,000
100,000
50,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24

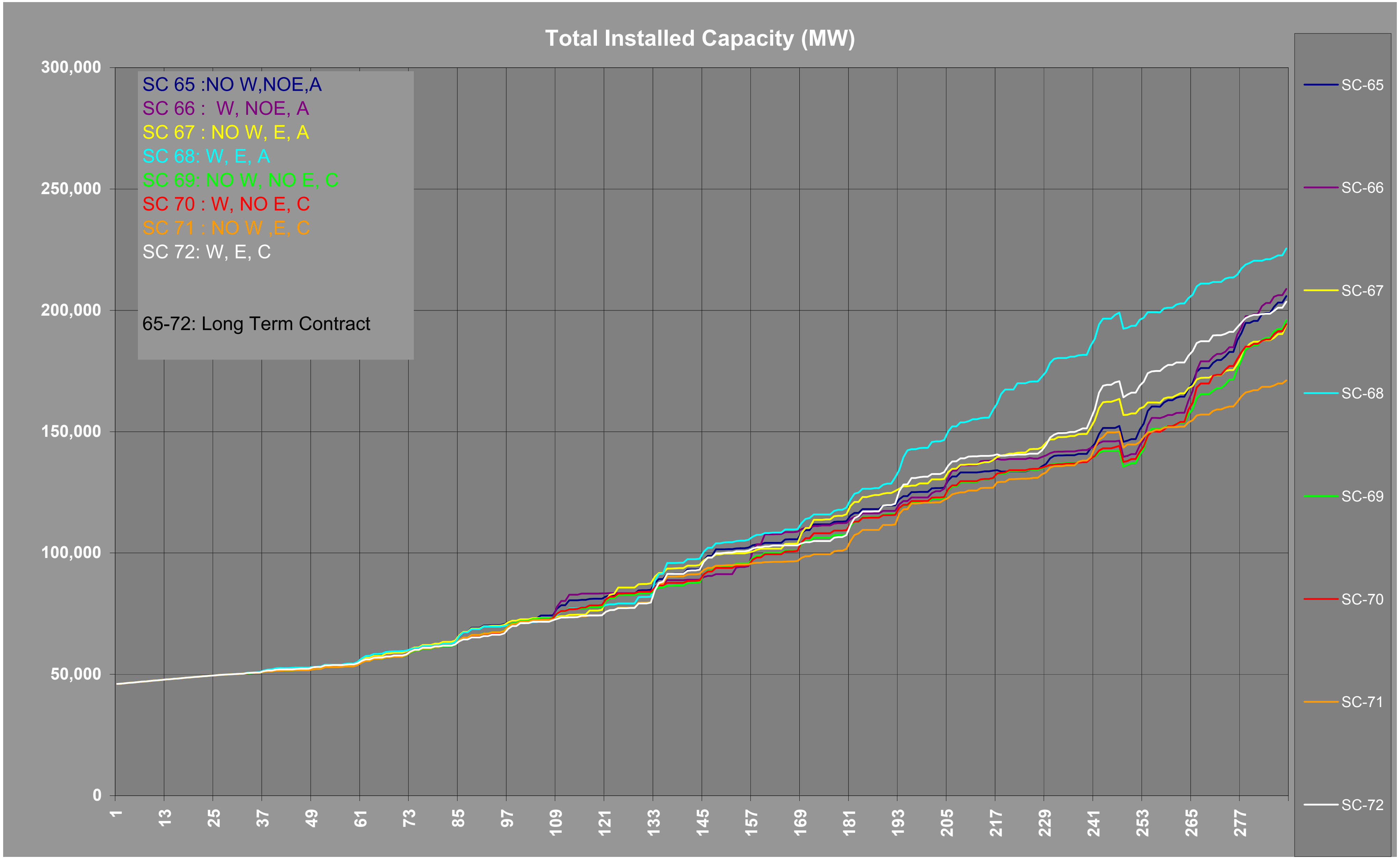


Total Installed Capacity (MW)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
300,000
250,000
200,000
150,000
100,000
50,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32

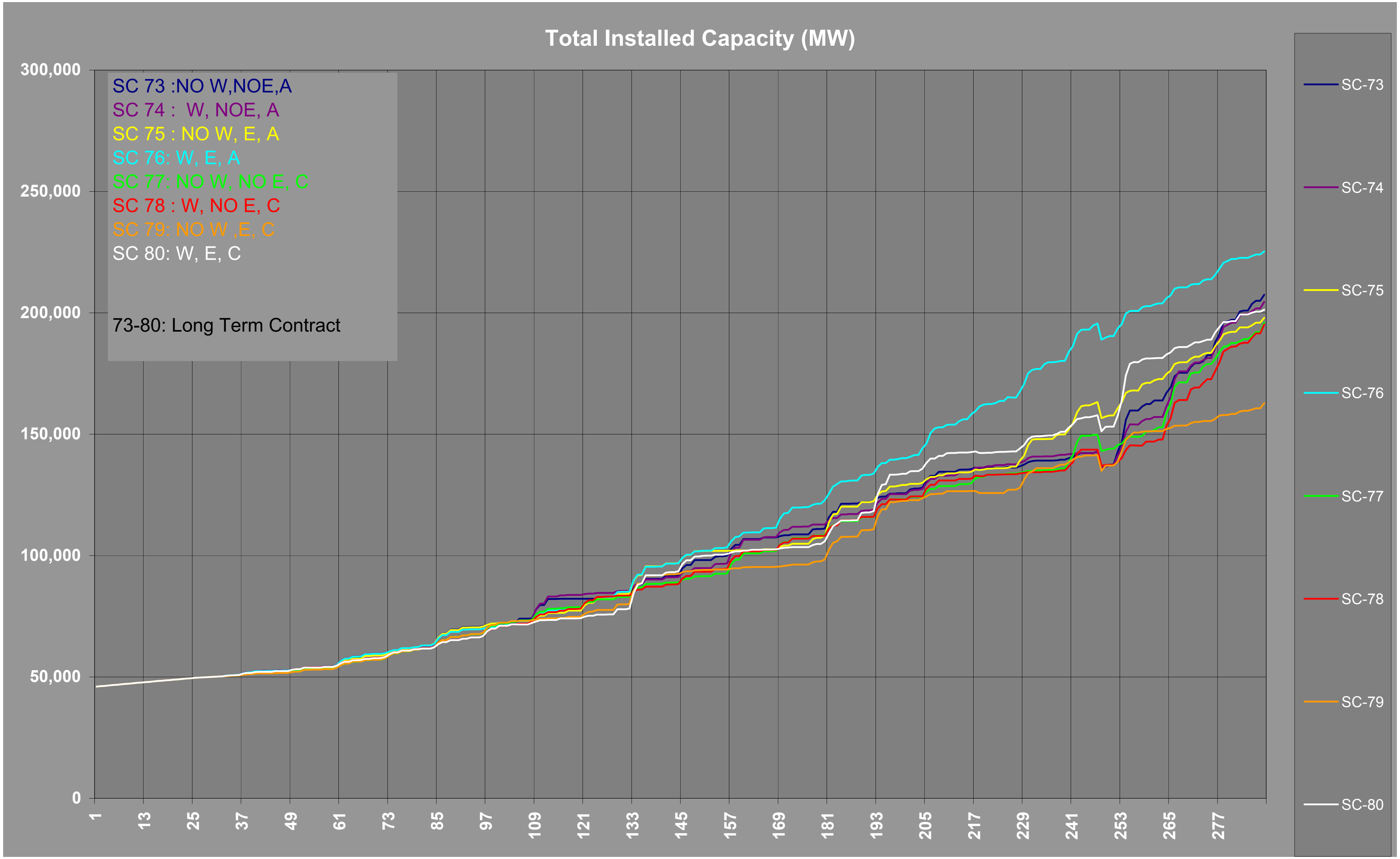

Total Installed Capacity (MW)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
300,000
250,000
200,000
150,000
100,000
50,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

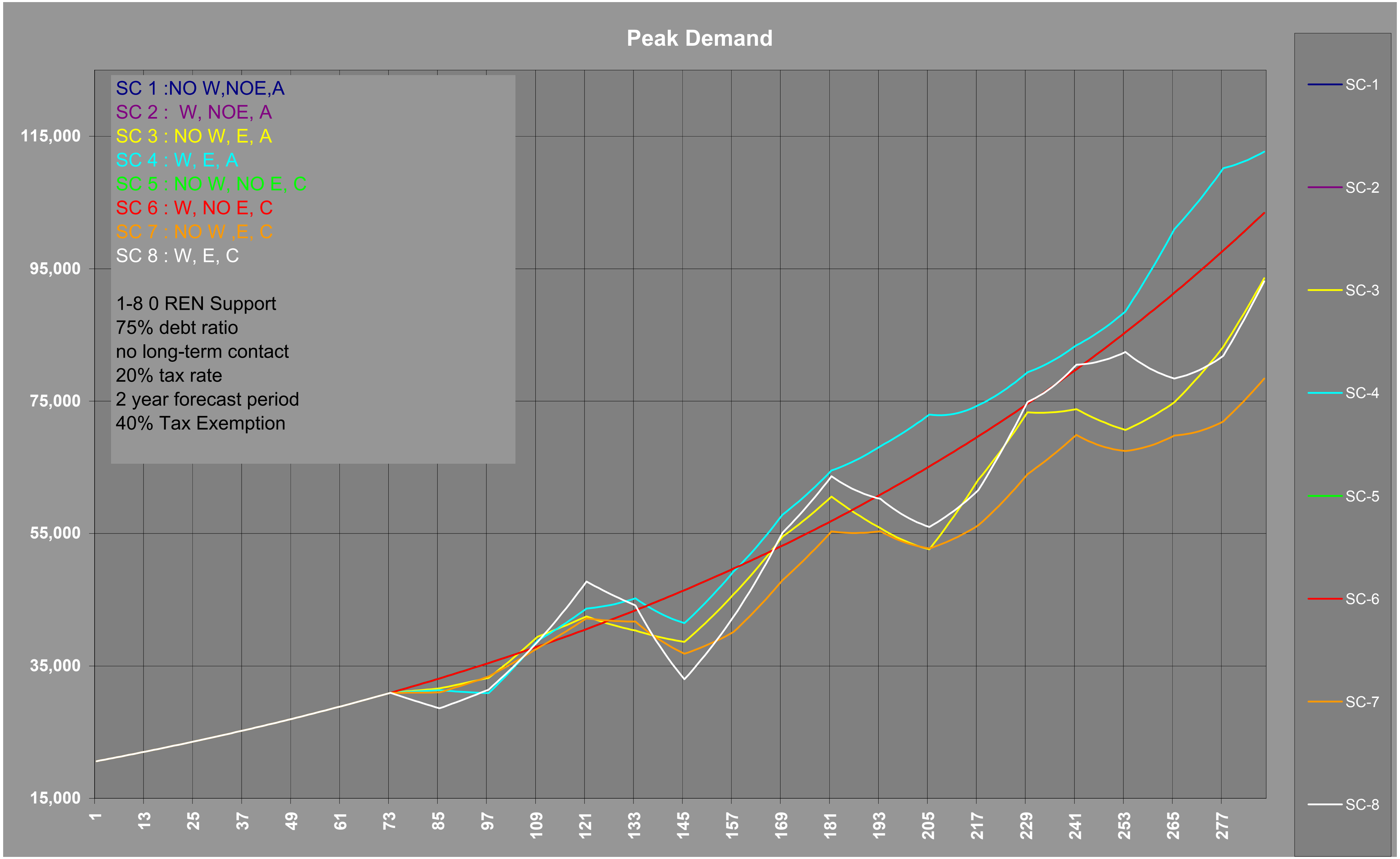


Total Installed Capacity (MW)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
300,000
250,000
200,000
150,000
100,000
50,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48

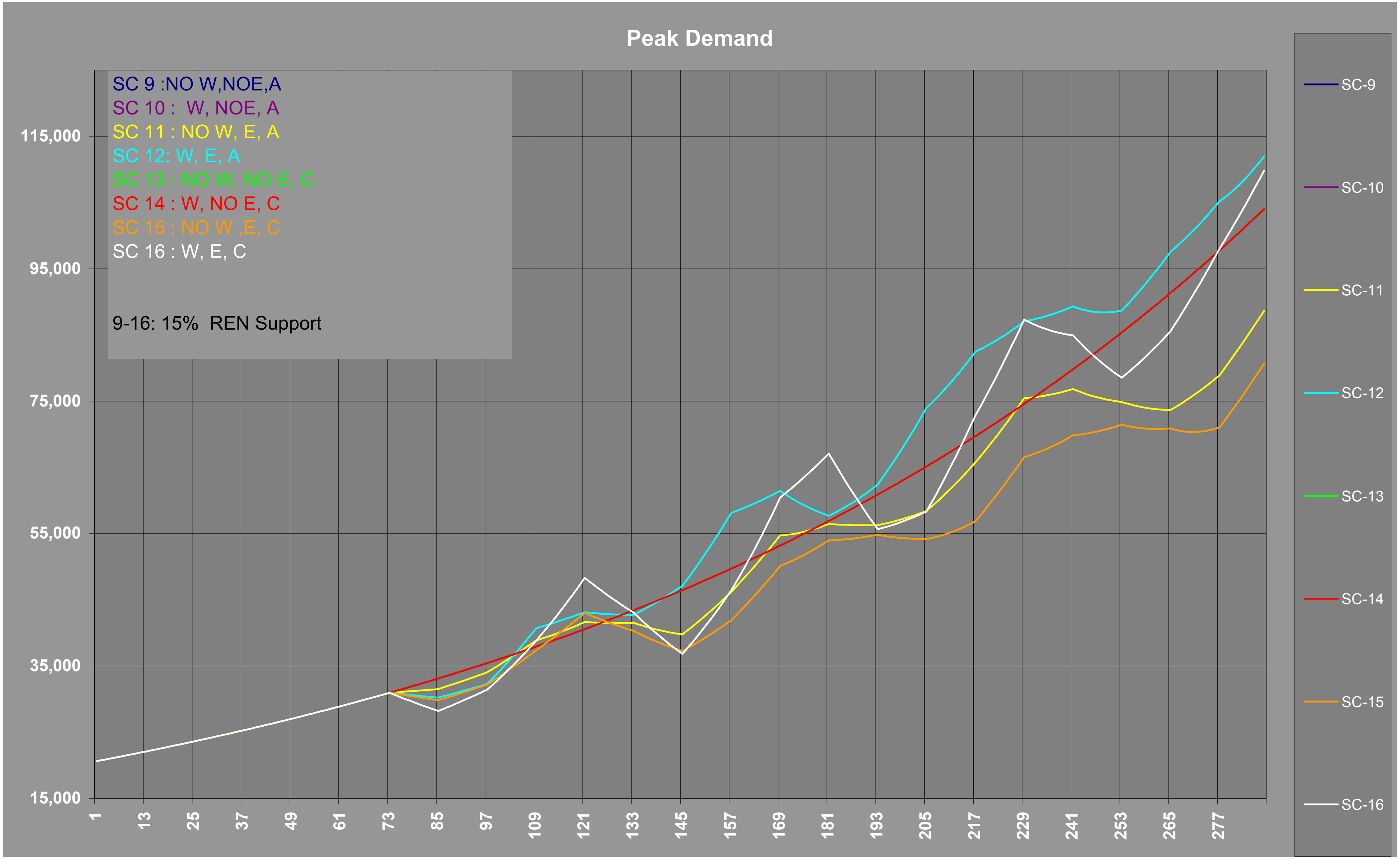


Total Installed Capacity (MW)
300,000
250,000
200,000
150,000
100,000
50,000
0
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

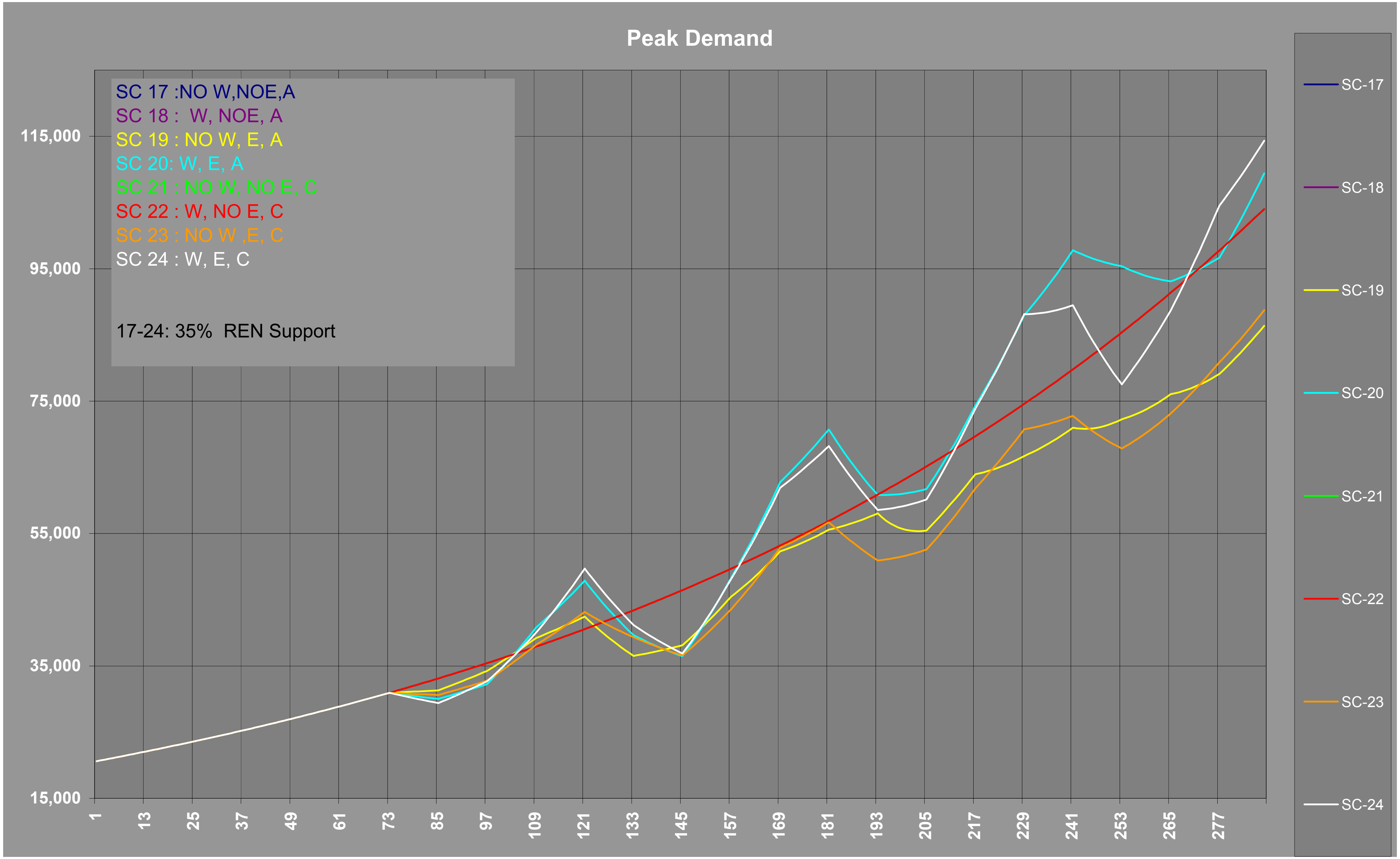

Total Installed Capacity (MW)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
300,000
250,000
200,000
150,000
100,000
50,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

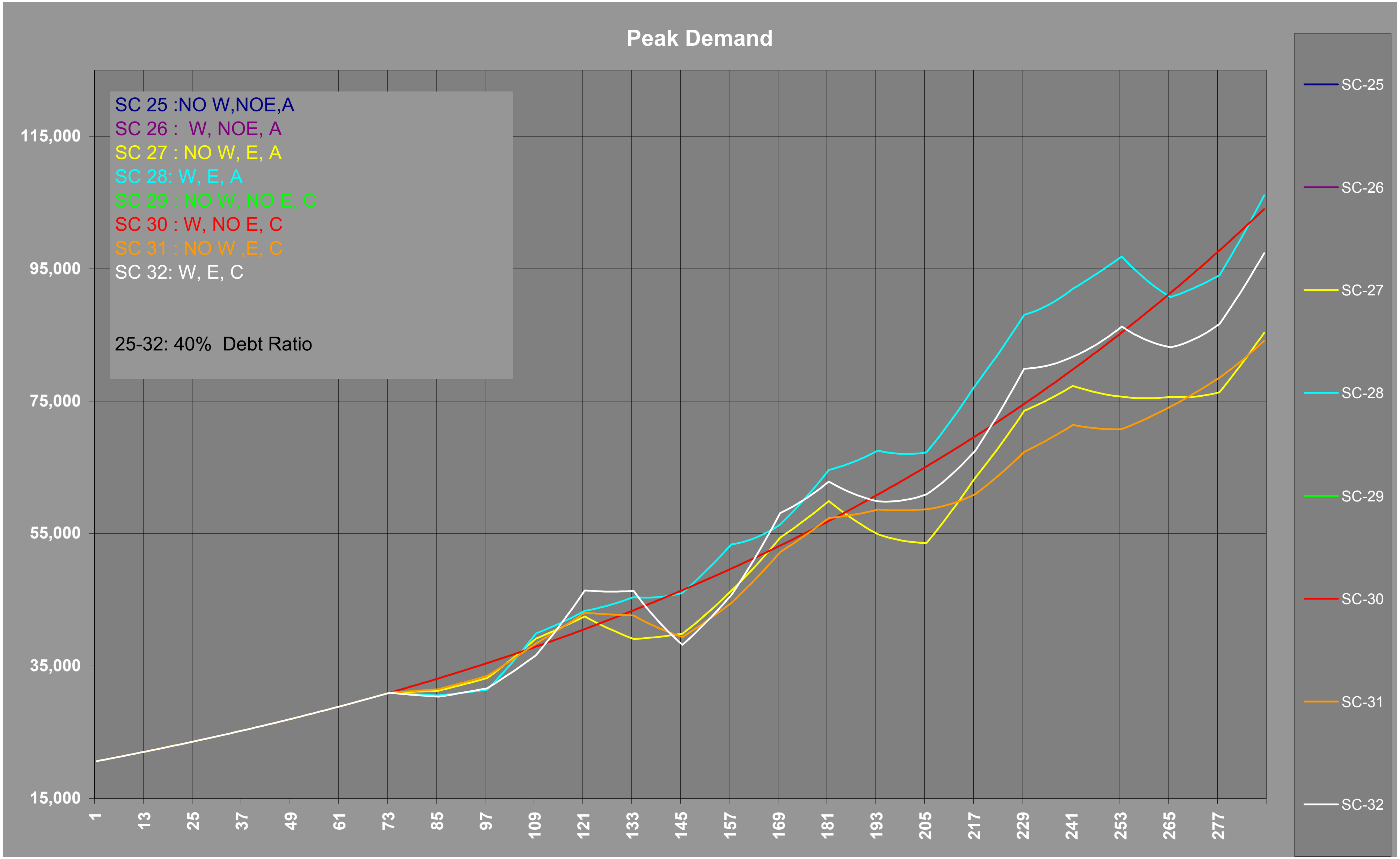


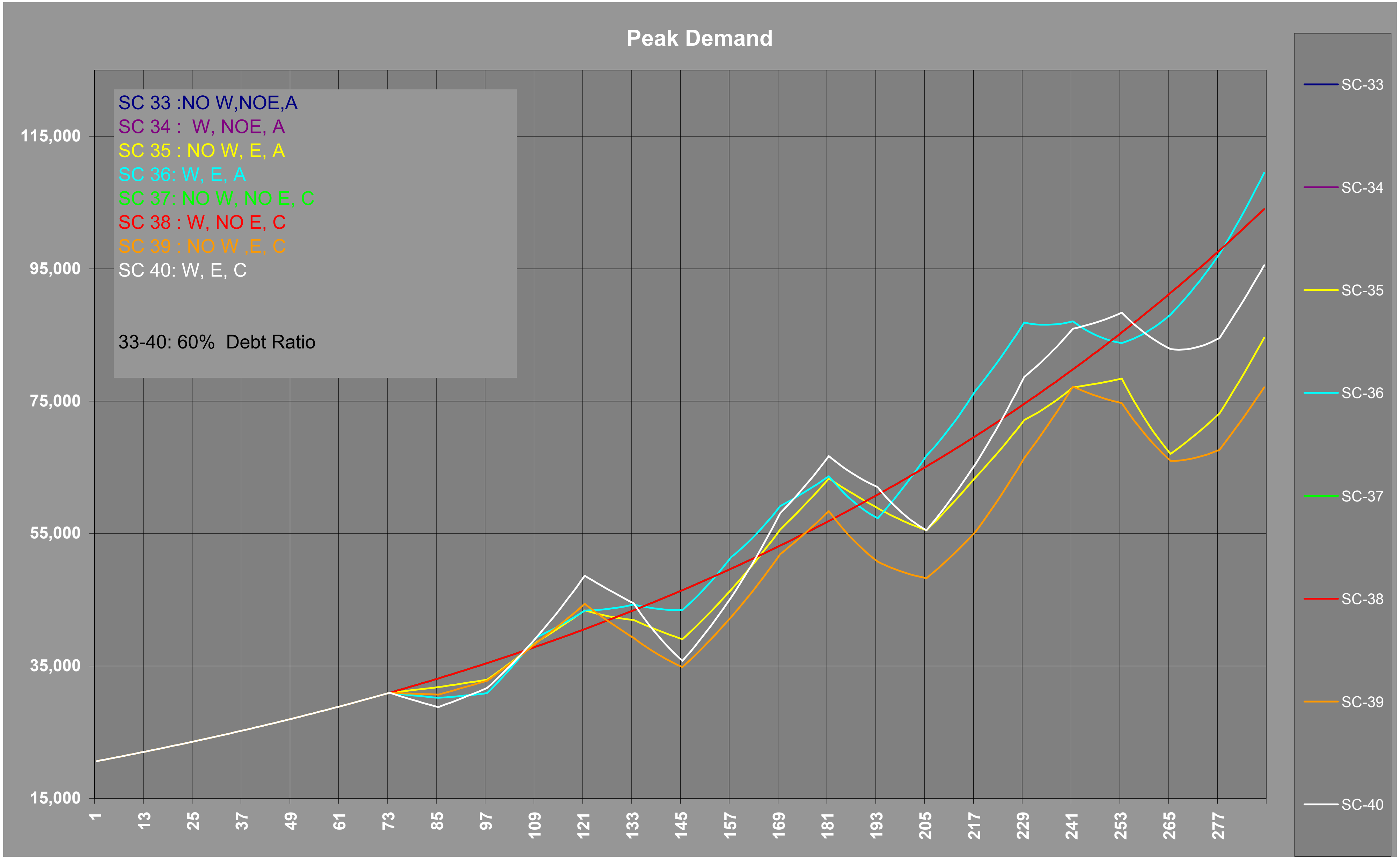
Peak Demand
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

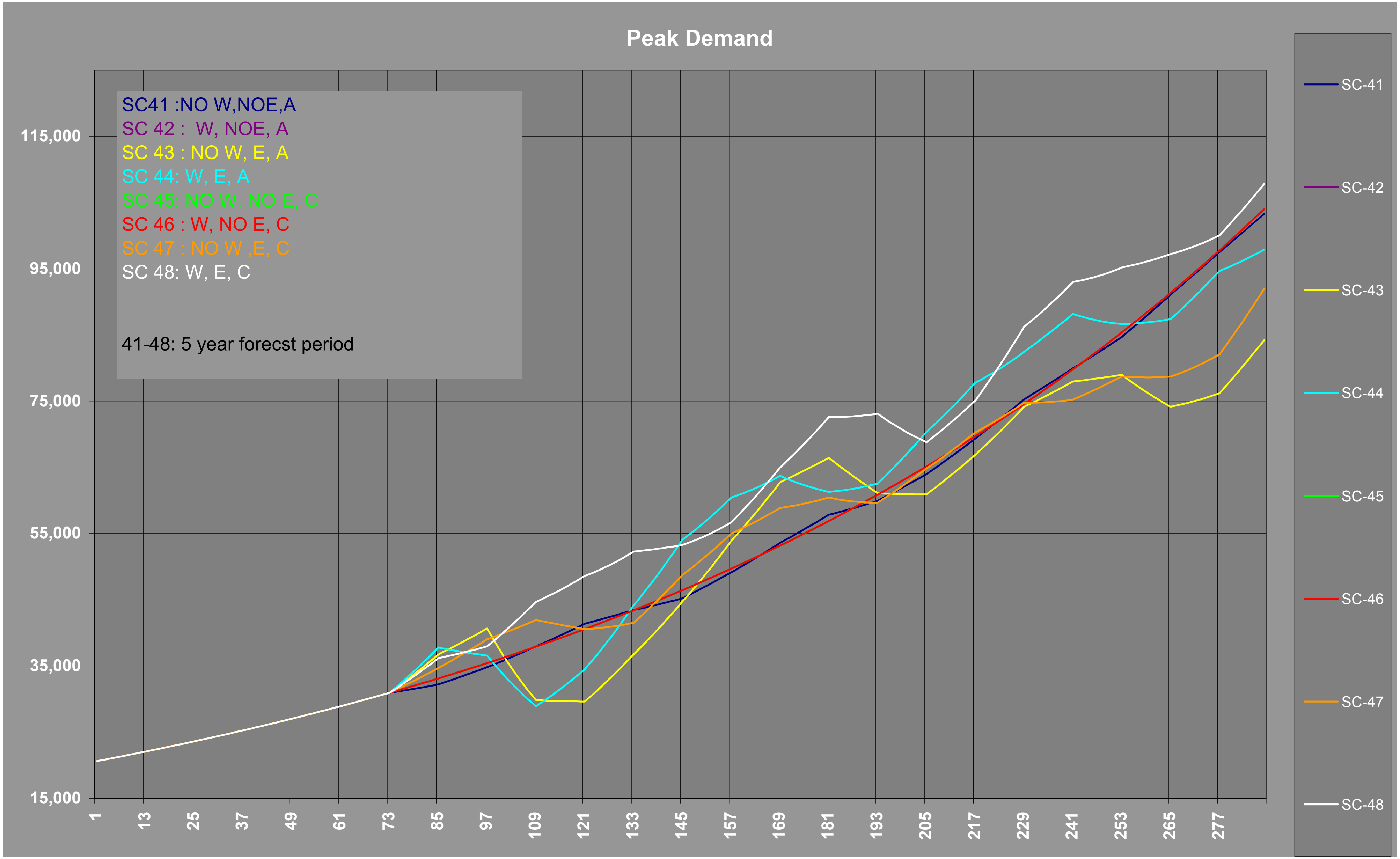


Peak Demand
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16

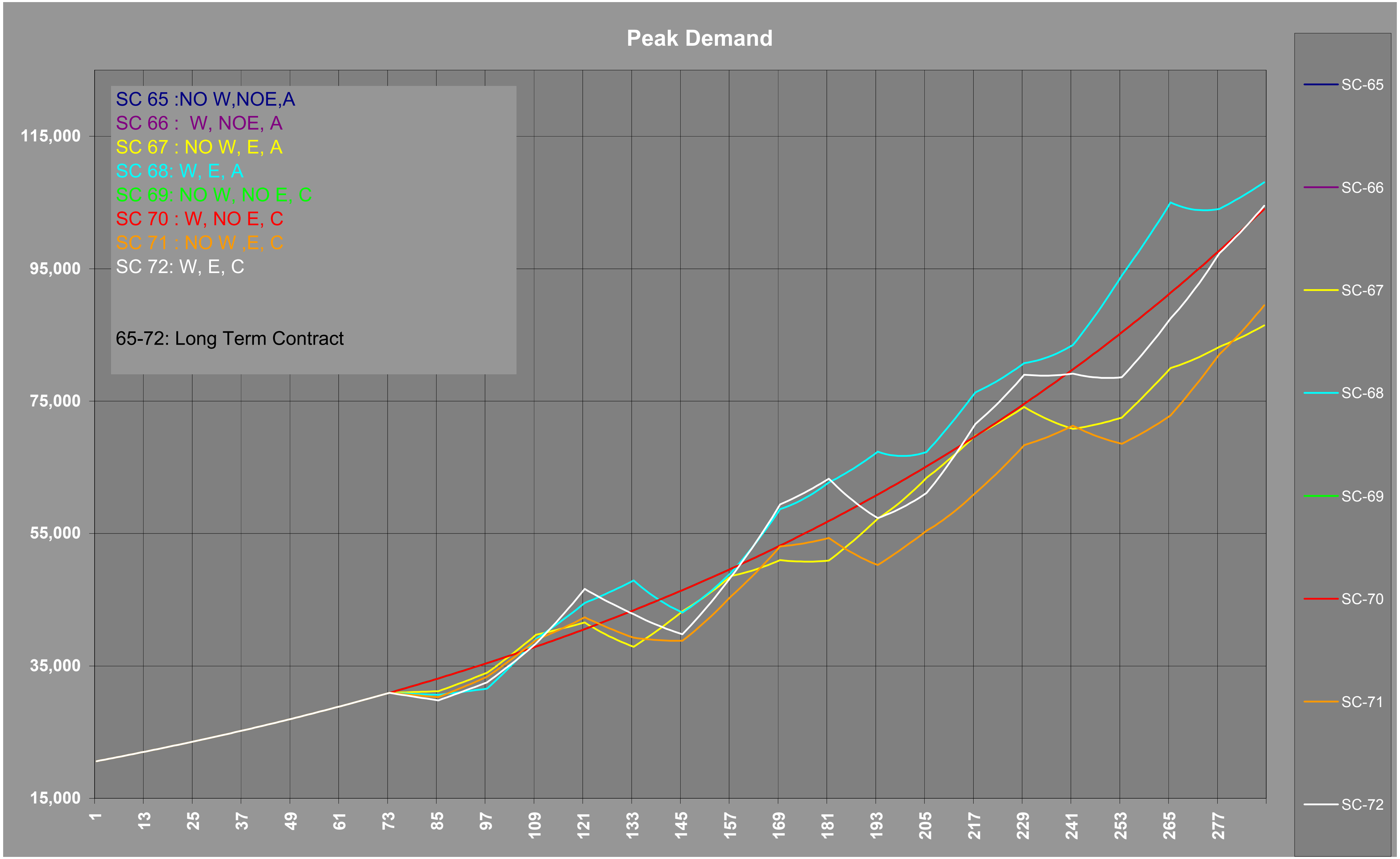

Peak Demand
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24


Peak Demand
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32

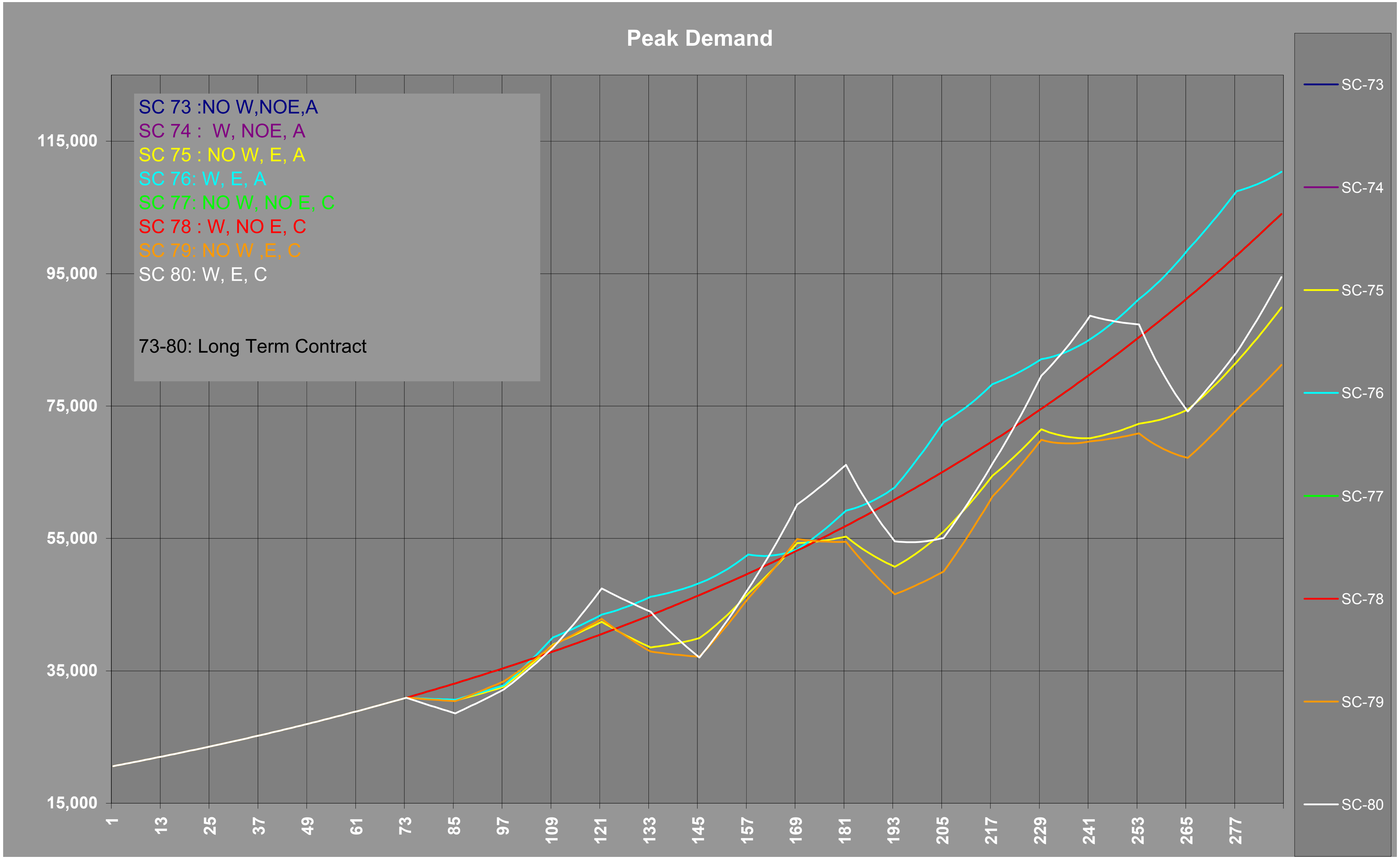

Peak Demand
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



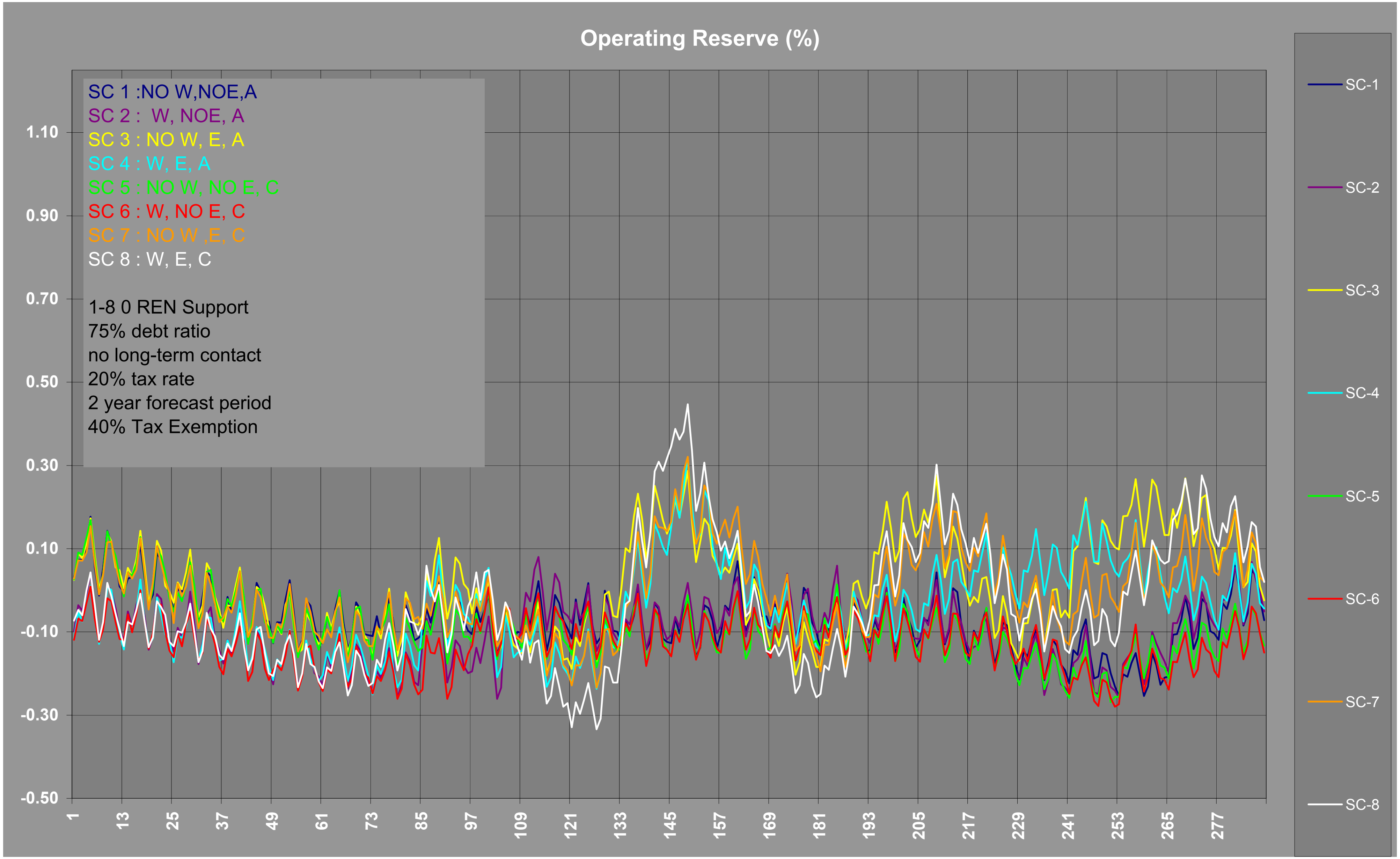
Peak Demand
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48

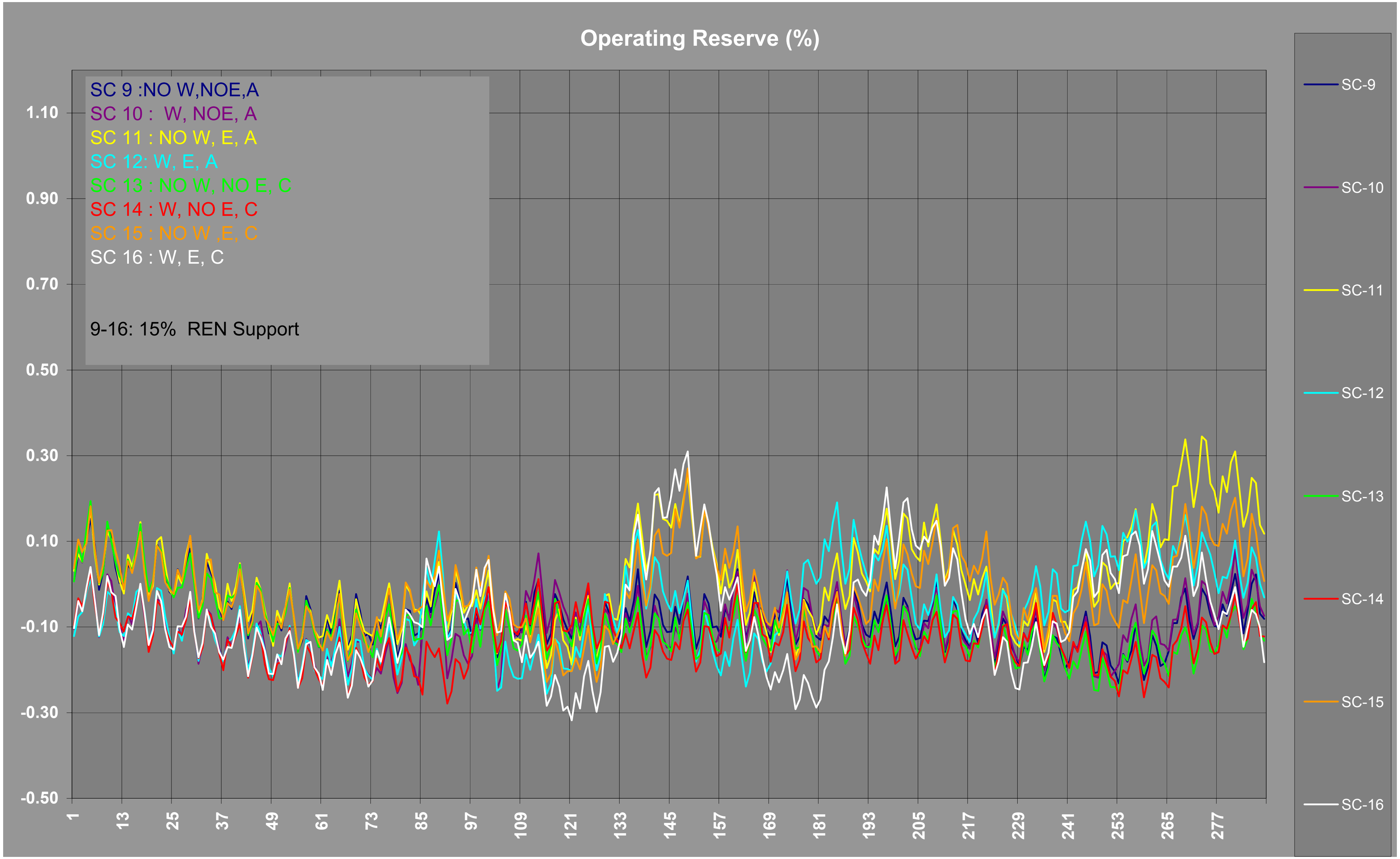


Peak Demand
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

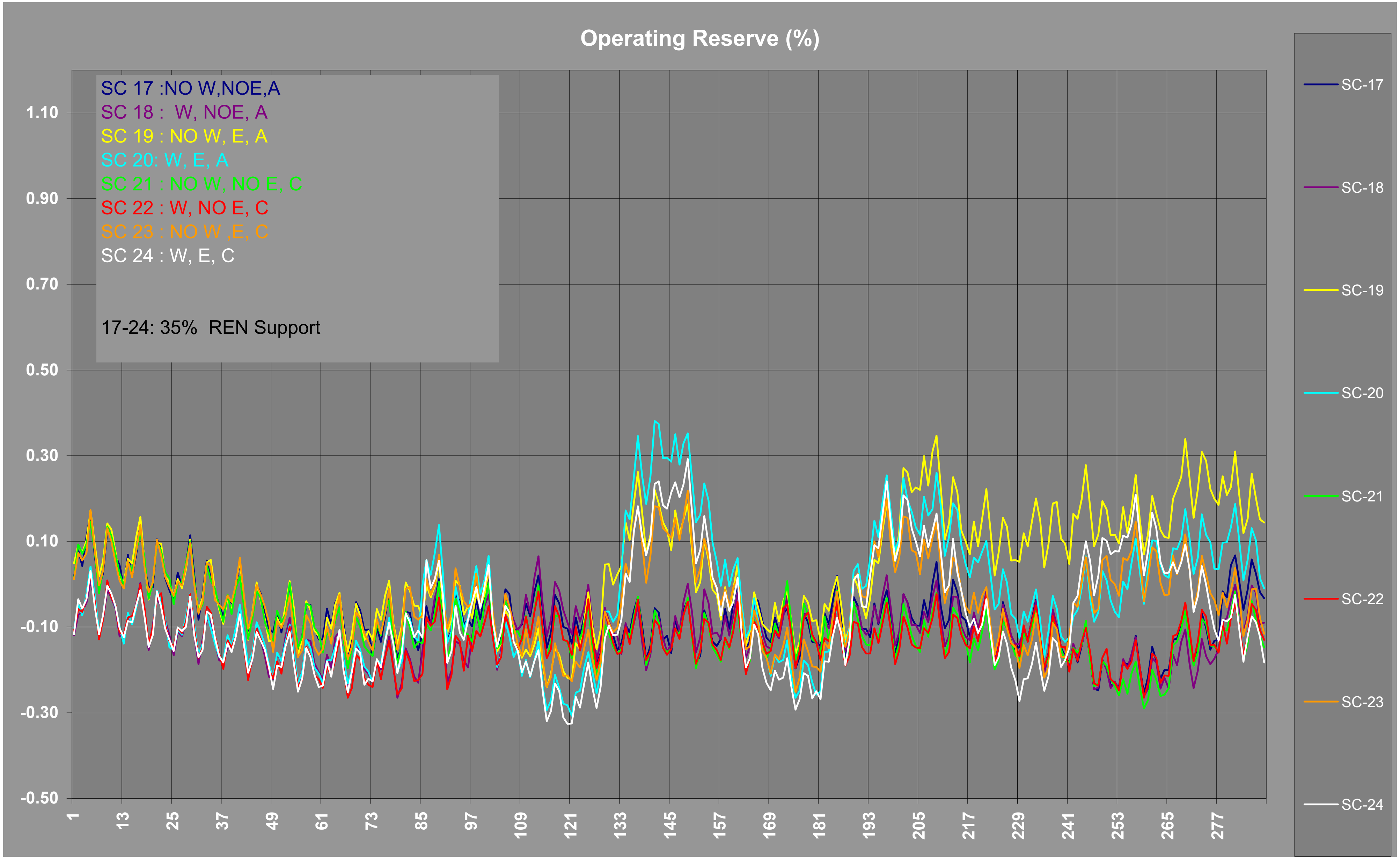


Peak Demand
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

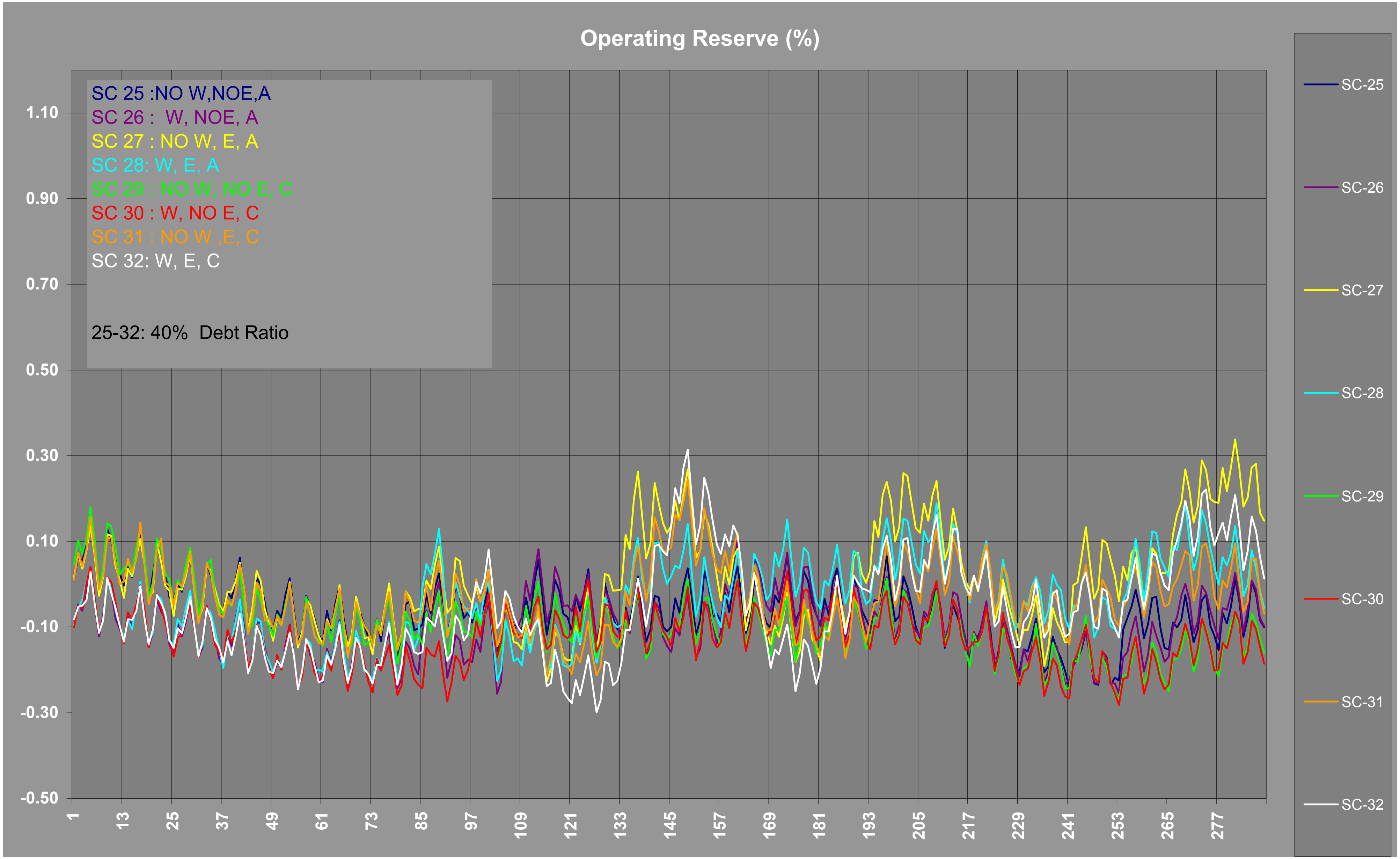

Operating Reserve (%)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
1.10
0.90
0.70
0.50
0.30
0.10
-0.10
-0.30
-0.50
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



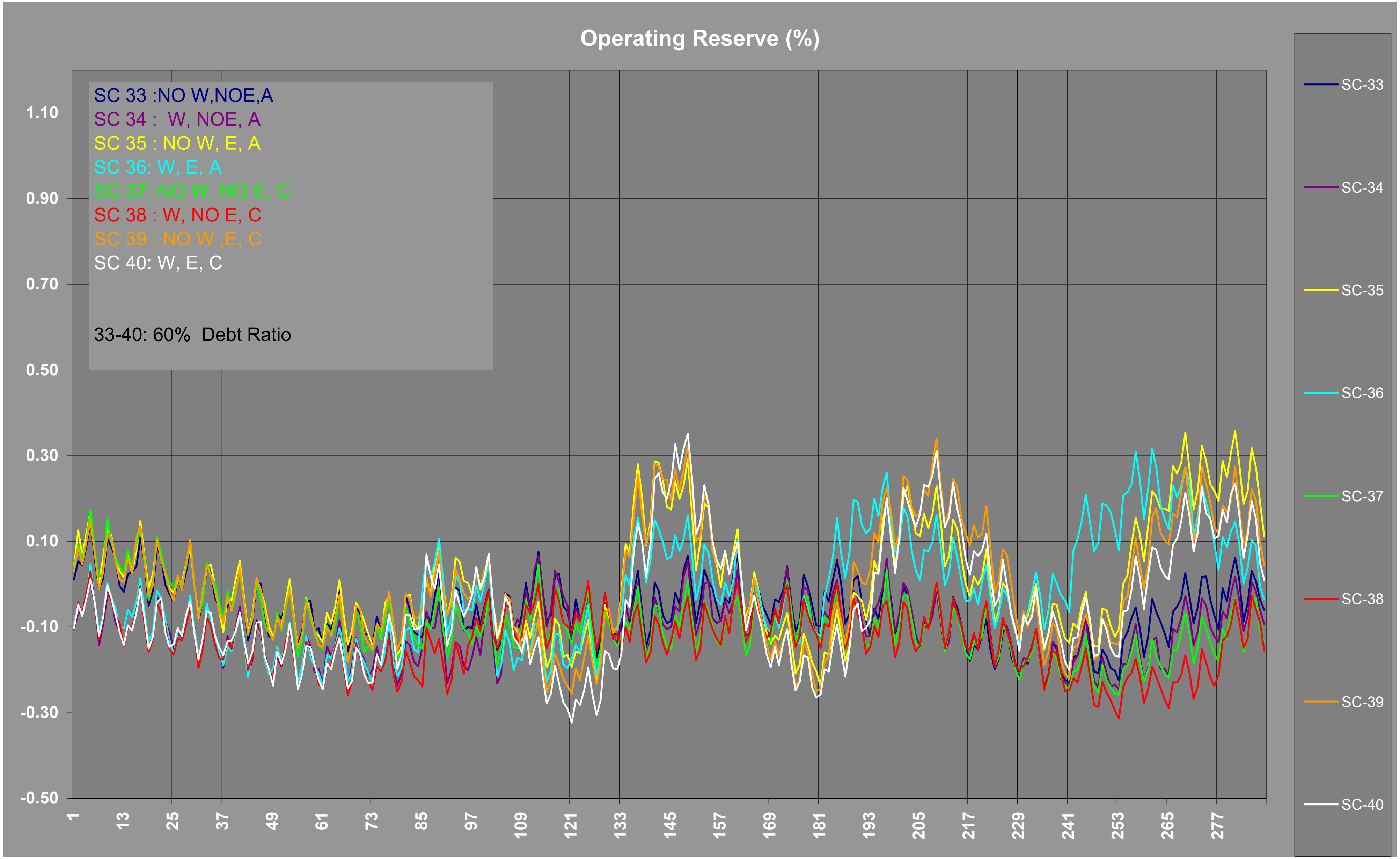
Operating Reserve (%)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
1.10
0.90
0.70
0.50
0.30
0.10
-0.10
-0.30
-0.50
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16

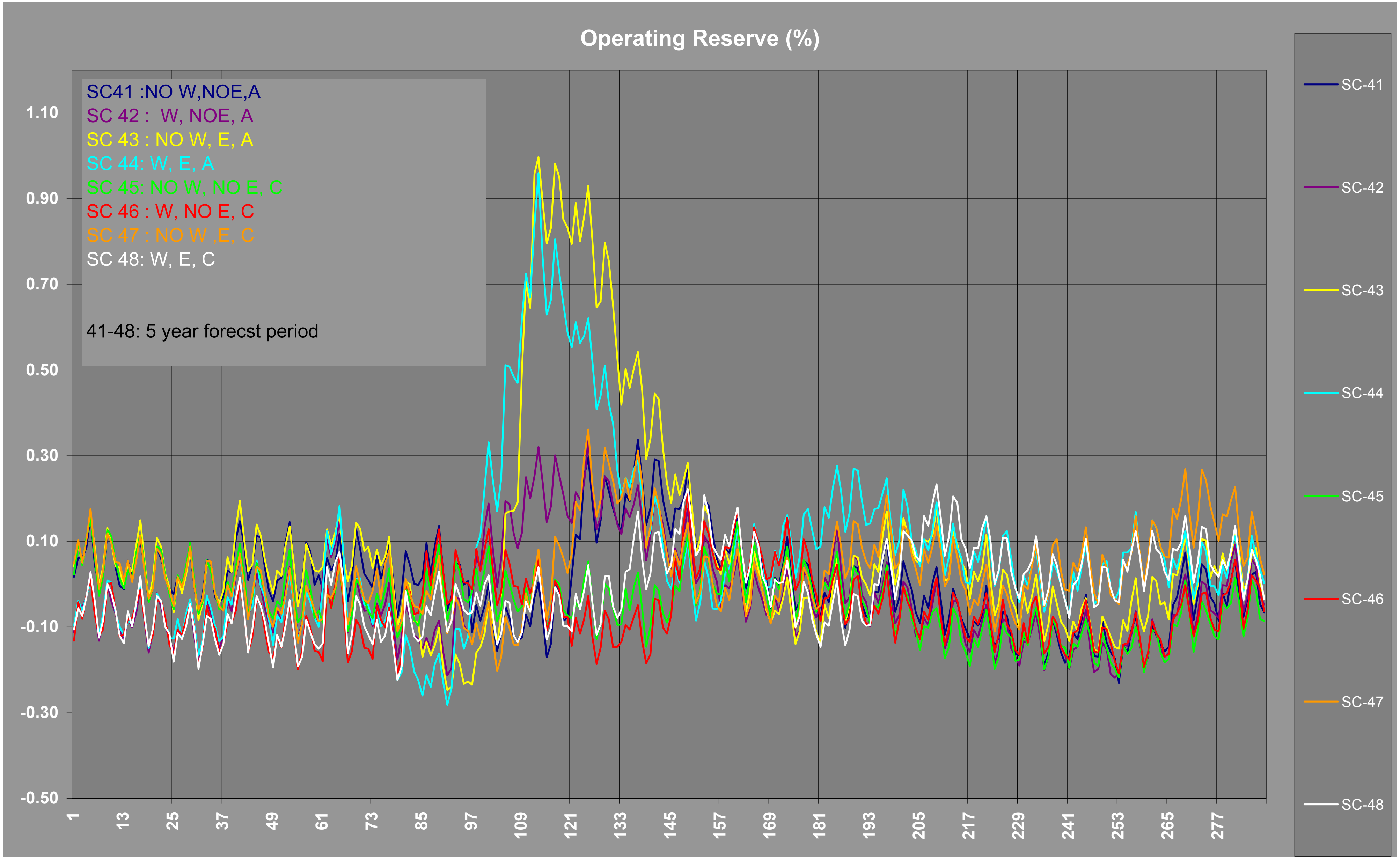


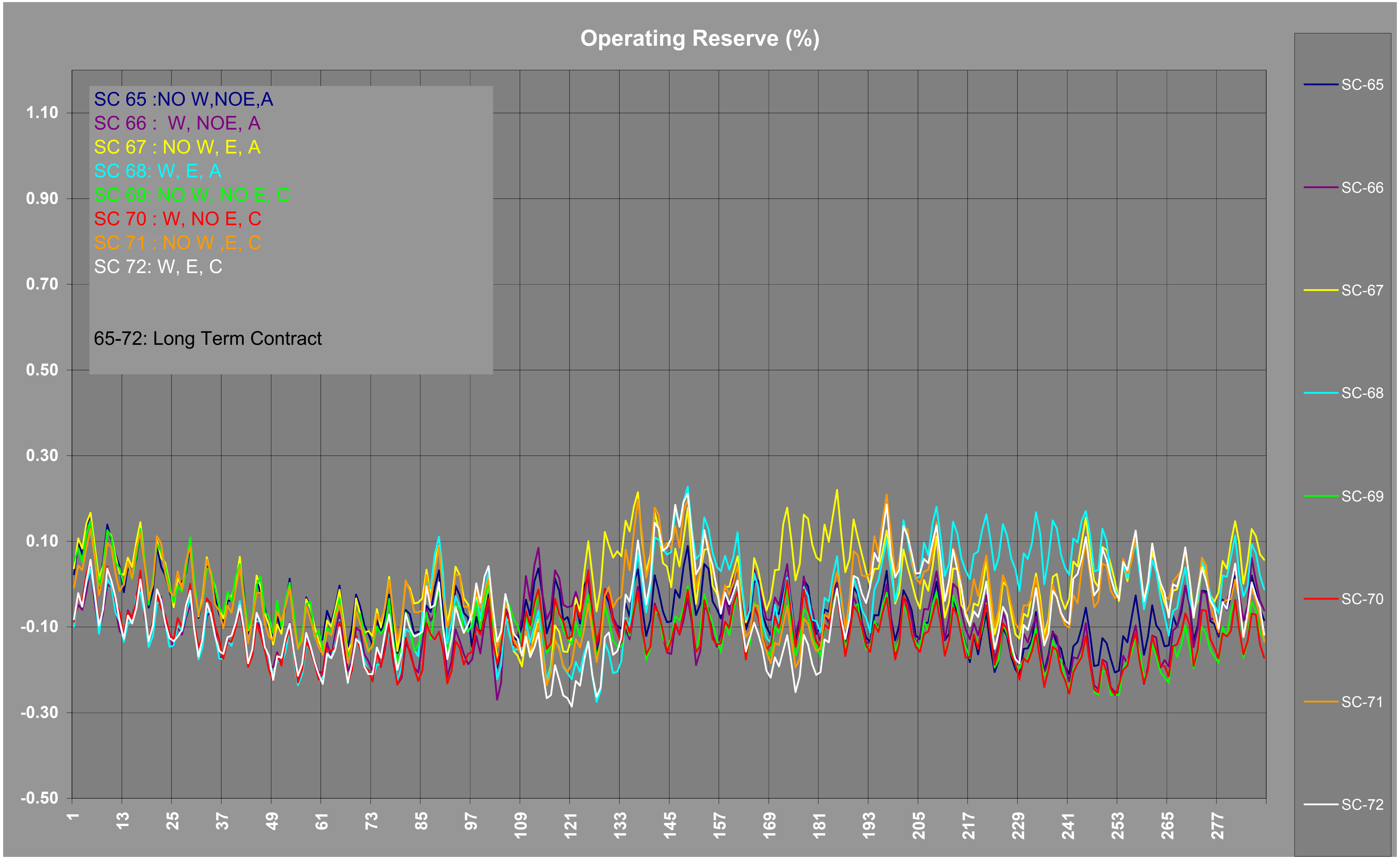
Operating Reserve (%)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
1.10
0.90
0.70
0.50
0.30
0.10
-0.10
-0.30
-0.50
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24



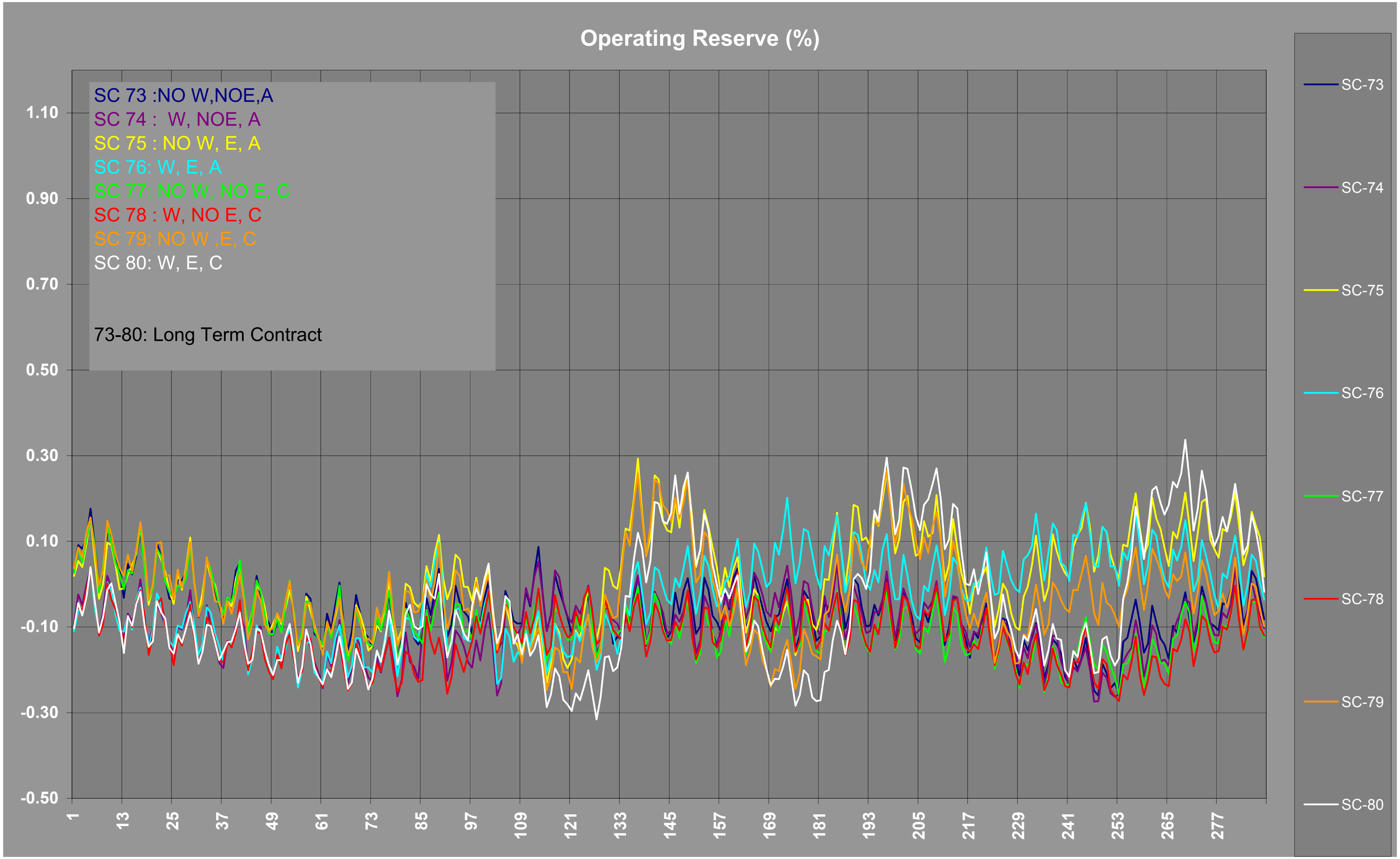
Operating Reserve (%)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
1.10
0.90
0.70
0.50
0.30
0.10
-0.10
-0.30
-0.50
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32

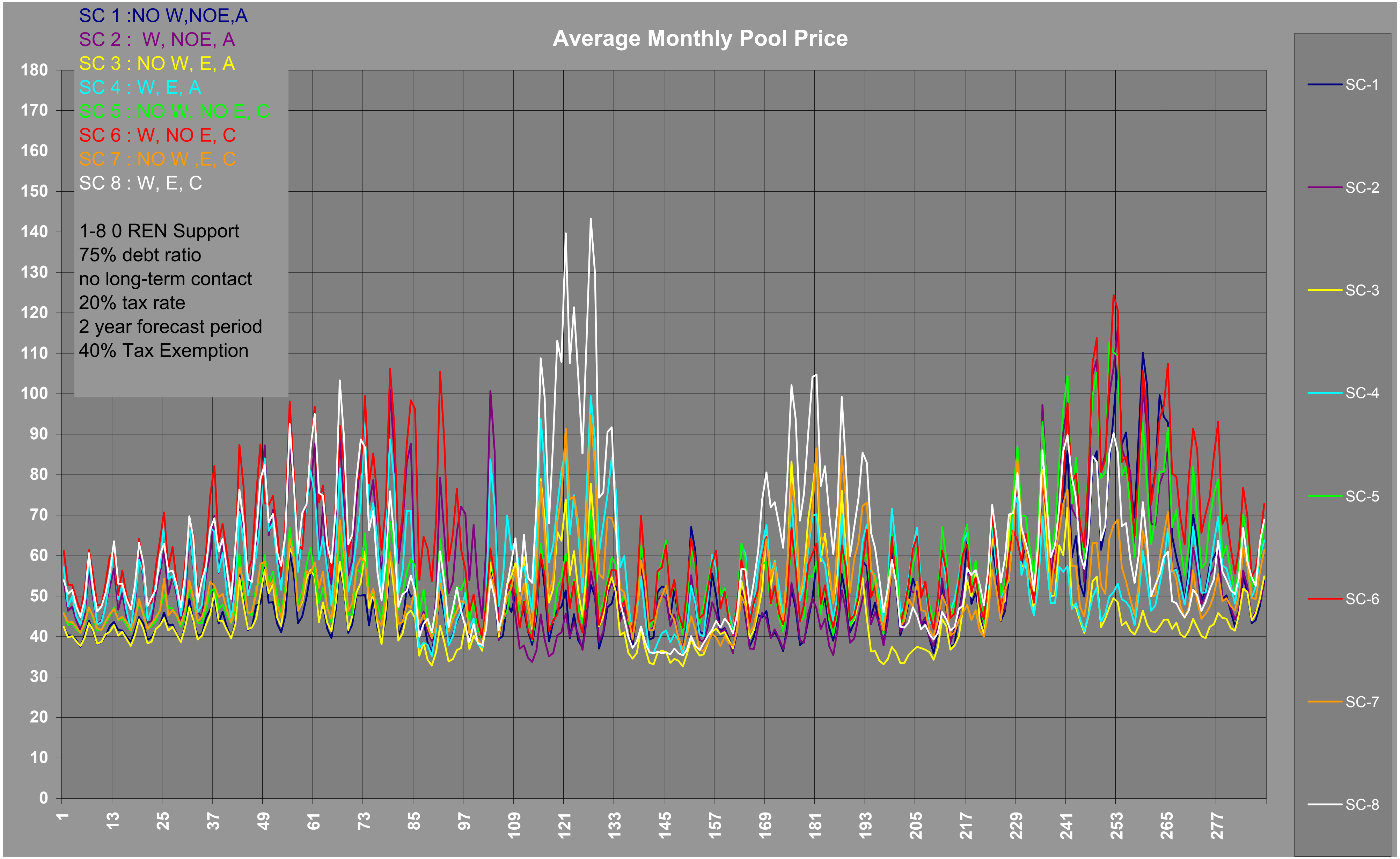

Operating Reserve (%)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
1.10
0.90
0.70
0.50
0.30
0.10
-0.10
-0.30
-0.50
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40


Operating Reserve (%)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
1.10
0.90
0.70
0.50
0.30
0.10
-0.10
-0.30
-0.50
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48

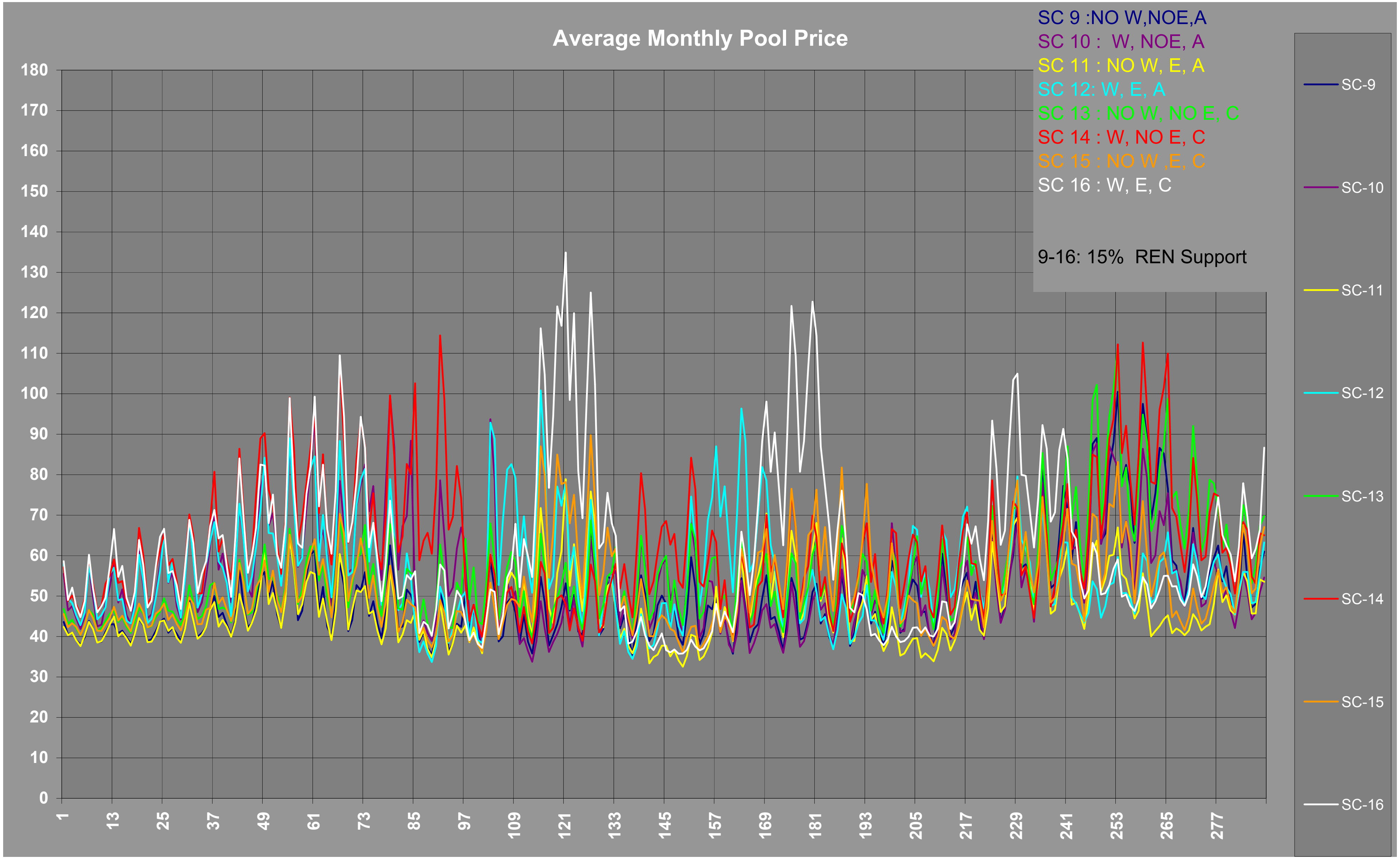


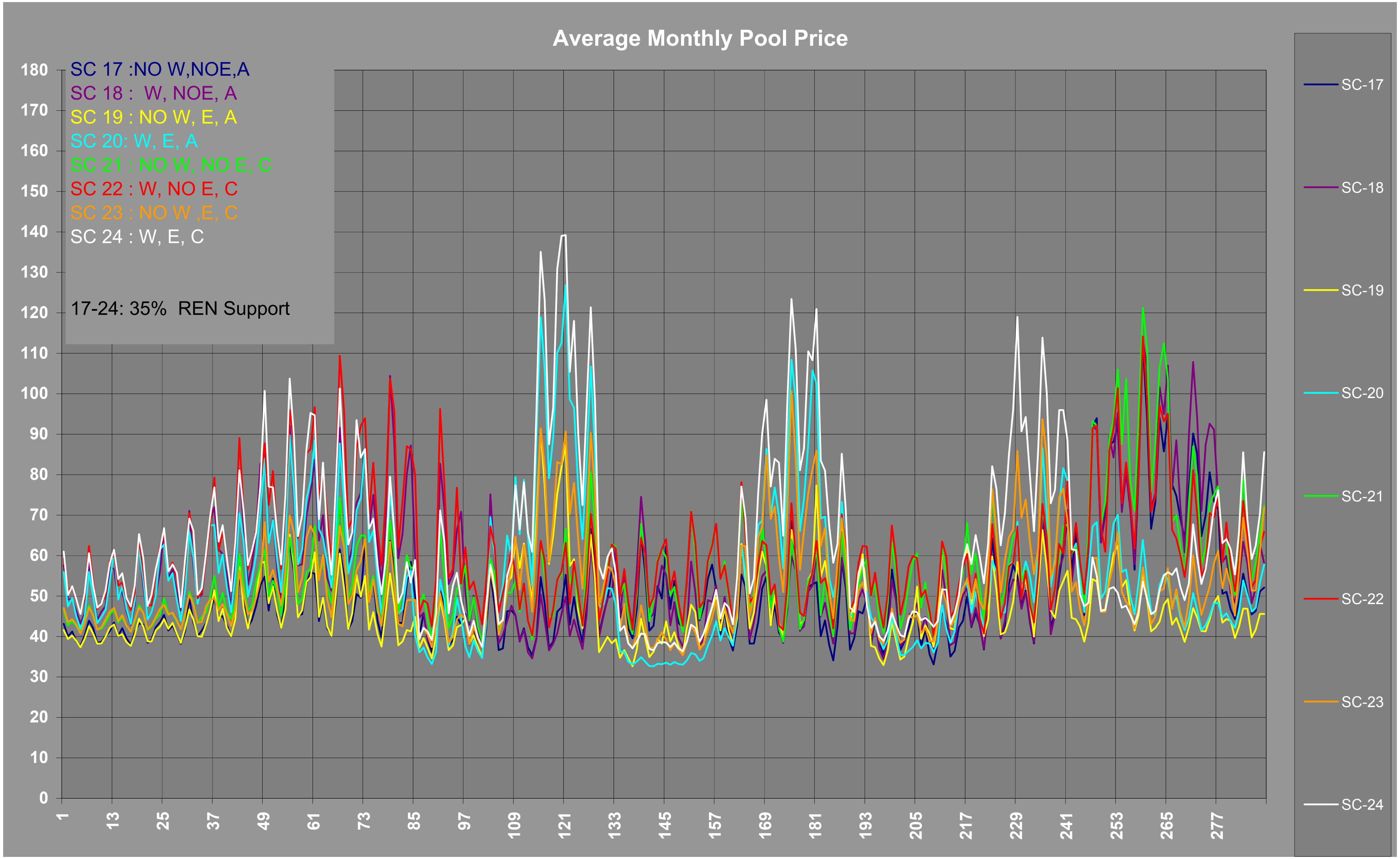
Operating Reserve (%)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
1.10
0.90
0.70
0.50
0.30
0.10
-0.10
-0.30
-0.50
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72


Operating Reserve (%)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
1.10
0.90
0.70
0.50
0.30
0.10
-0.10
-0.30
-0.50
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

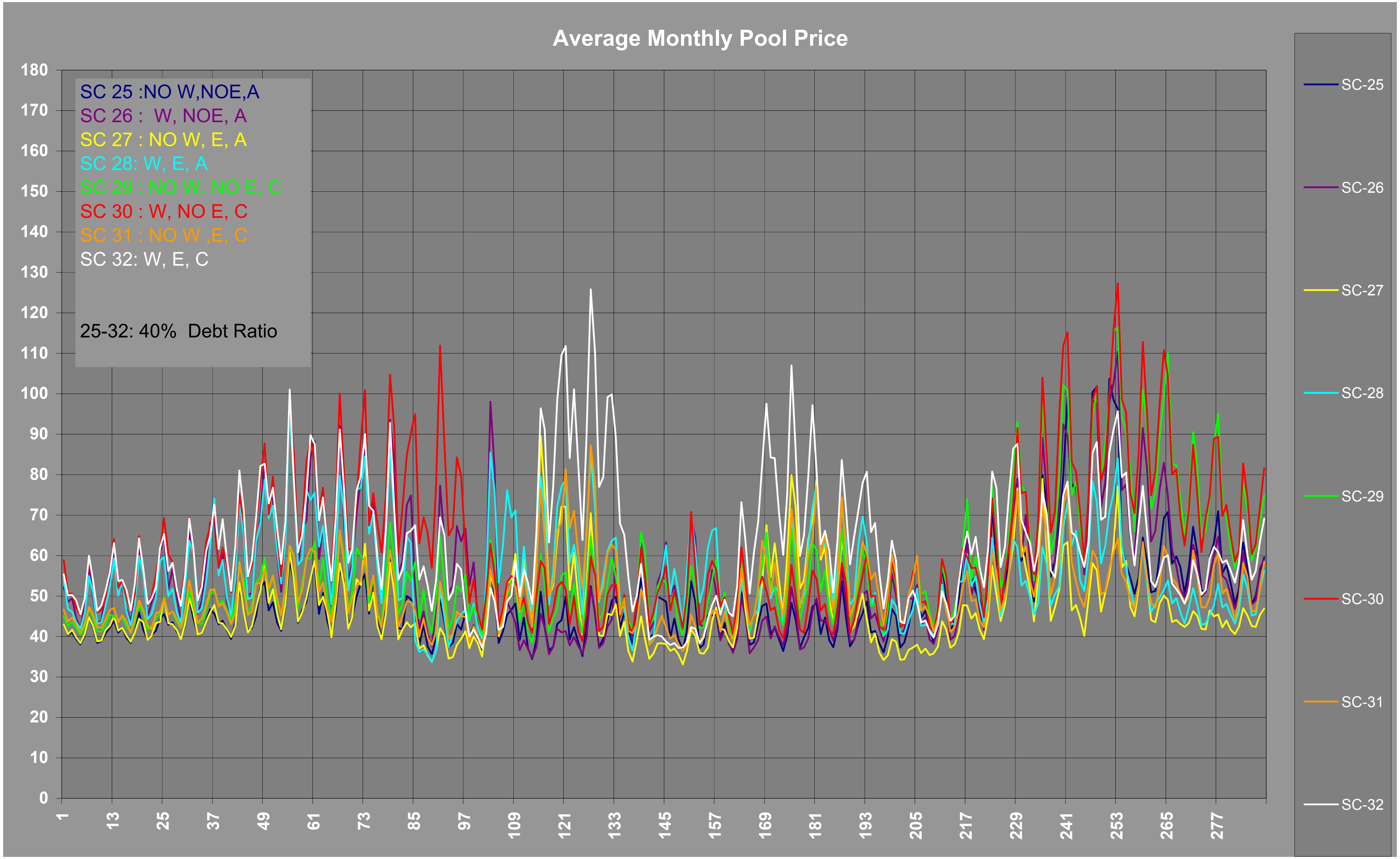


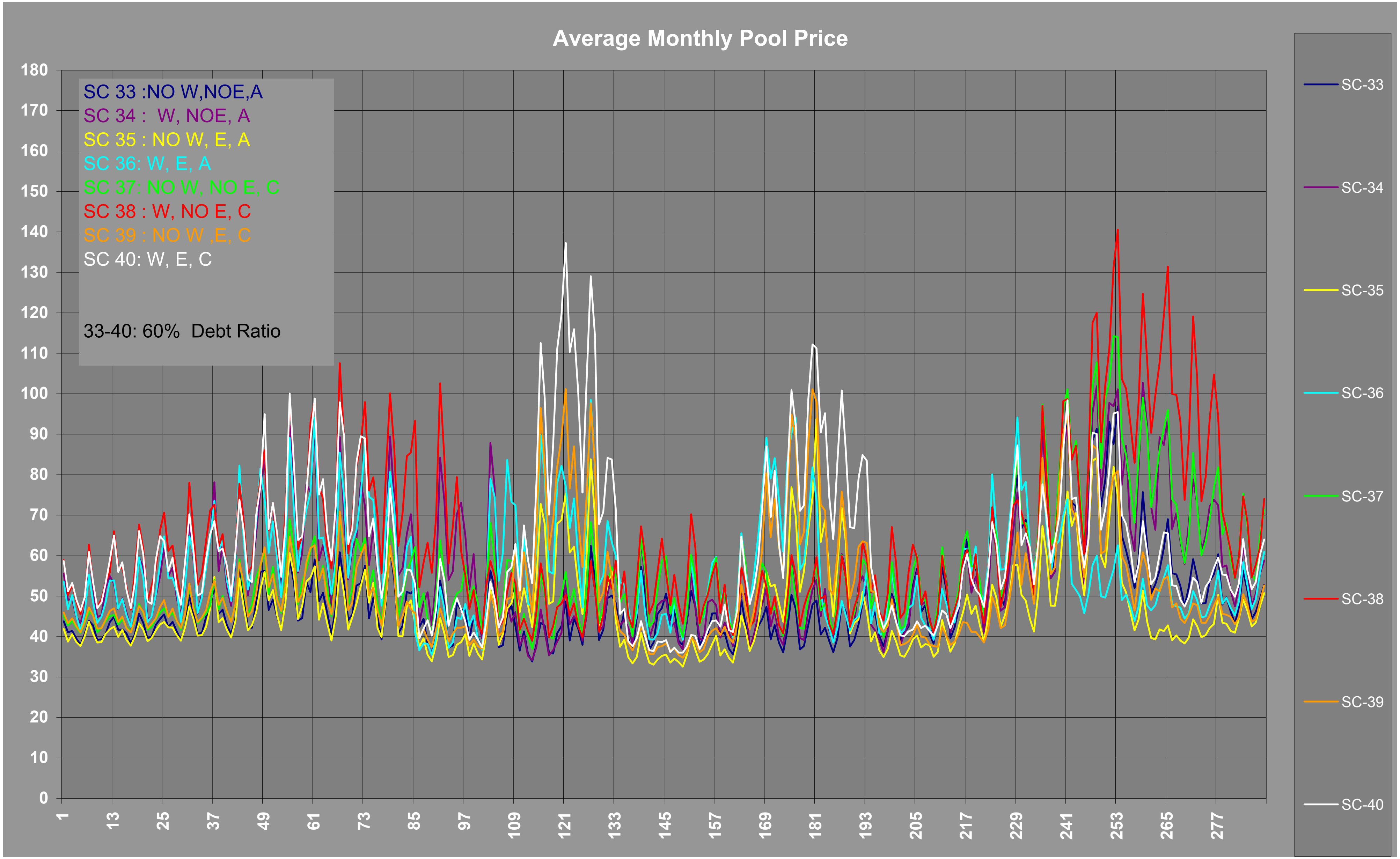
Average Monthly Pool Price
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

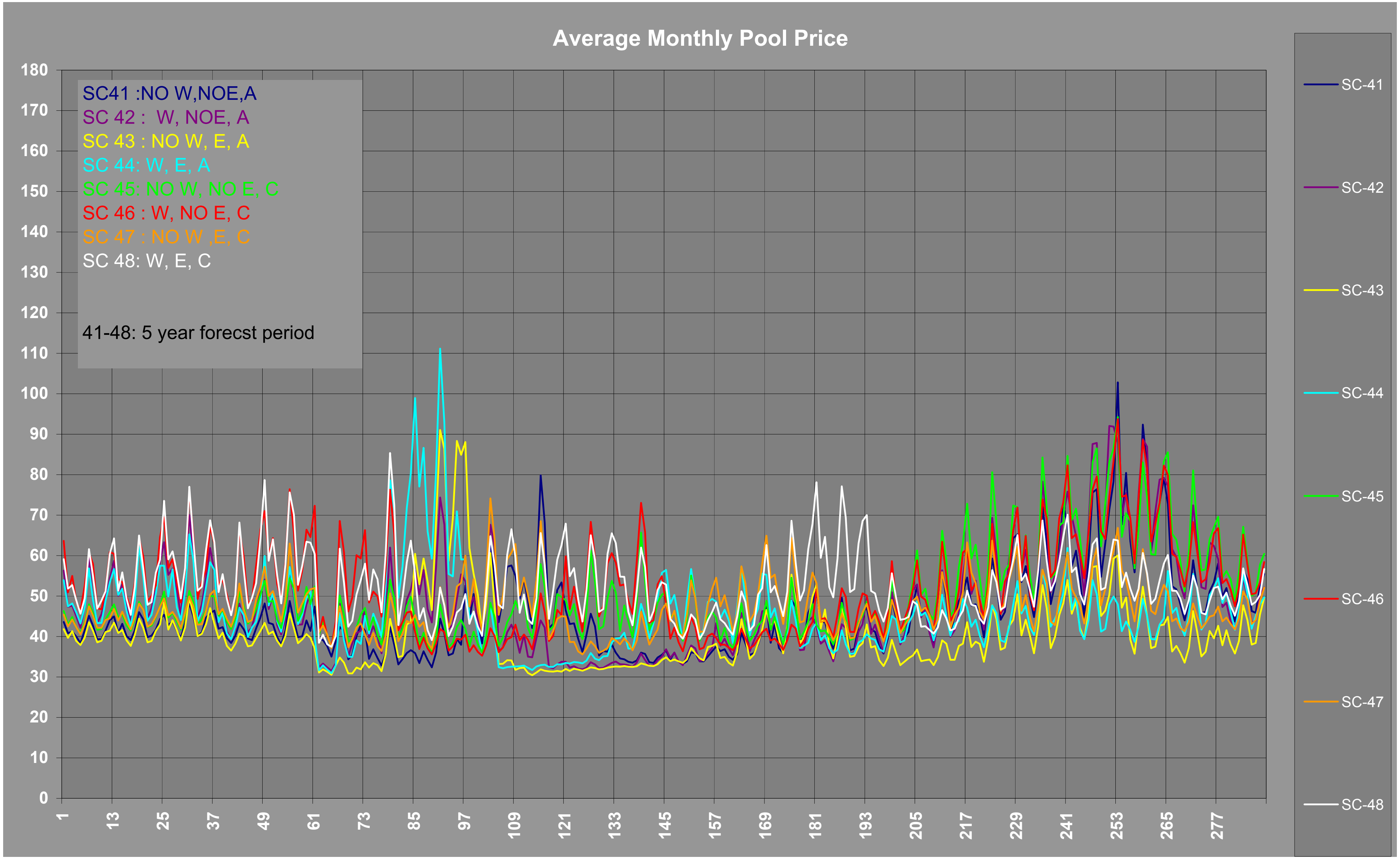

Average Monthly Pool Price
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277

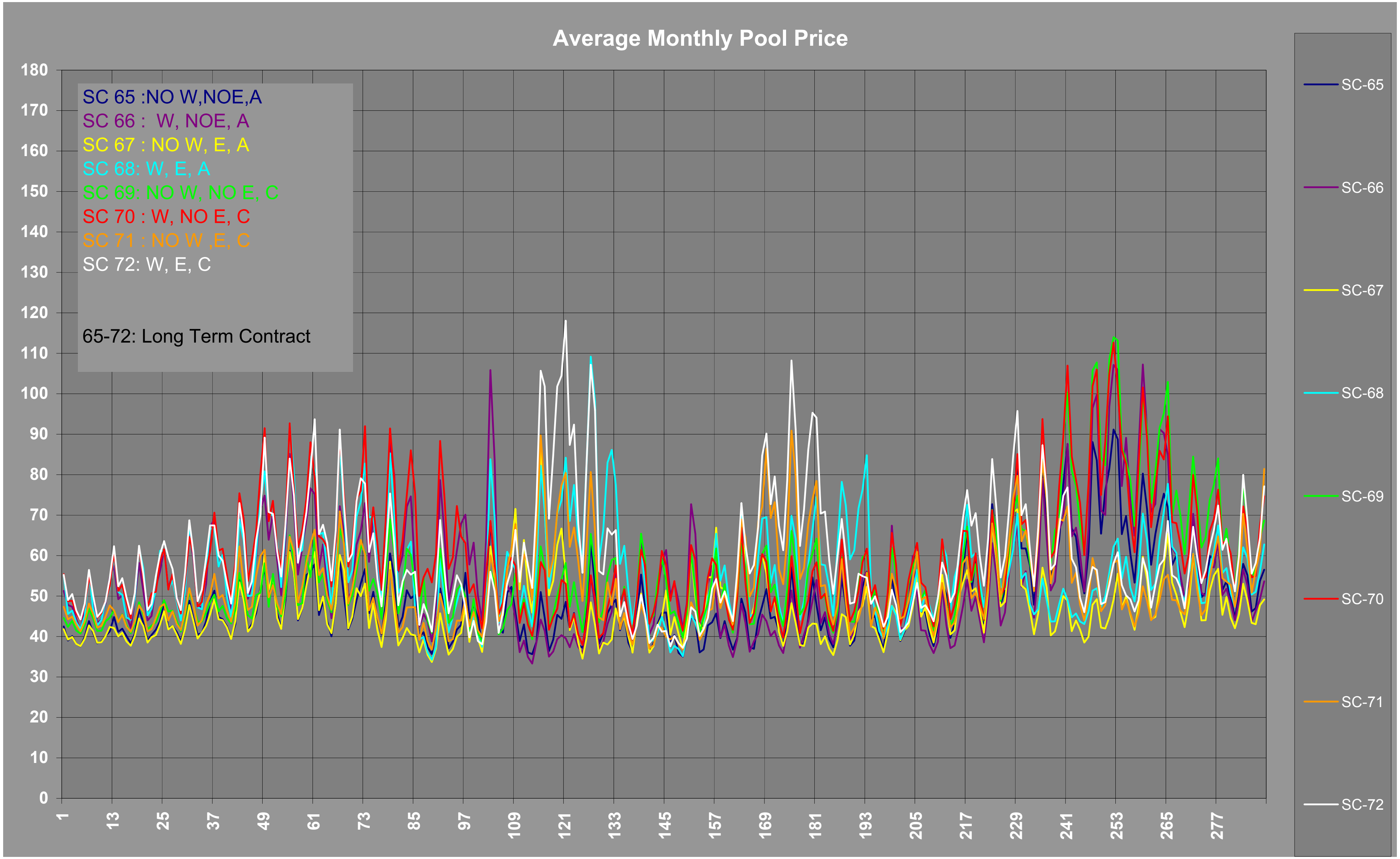


Average Monthly Pool Price
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24

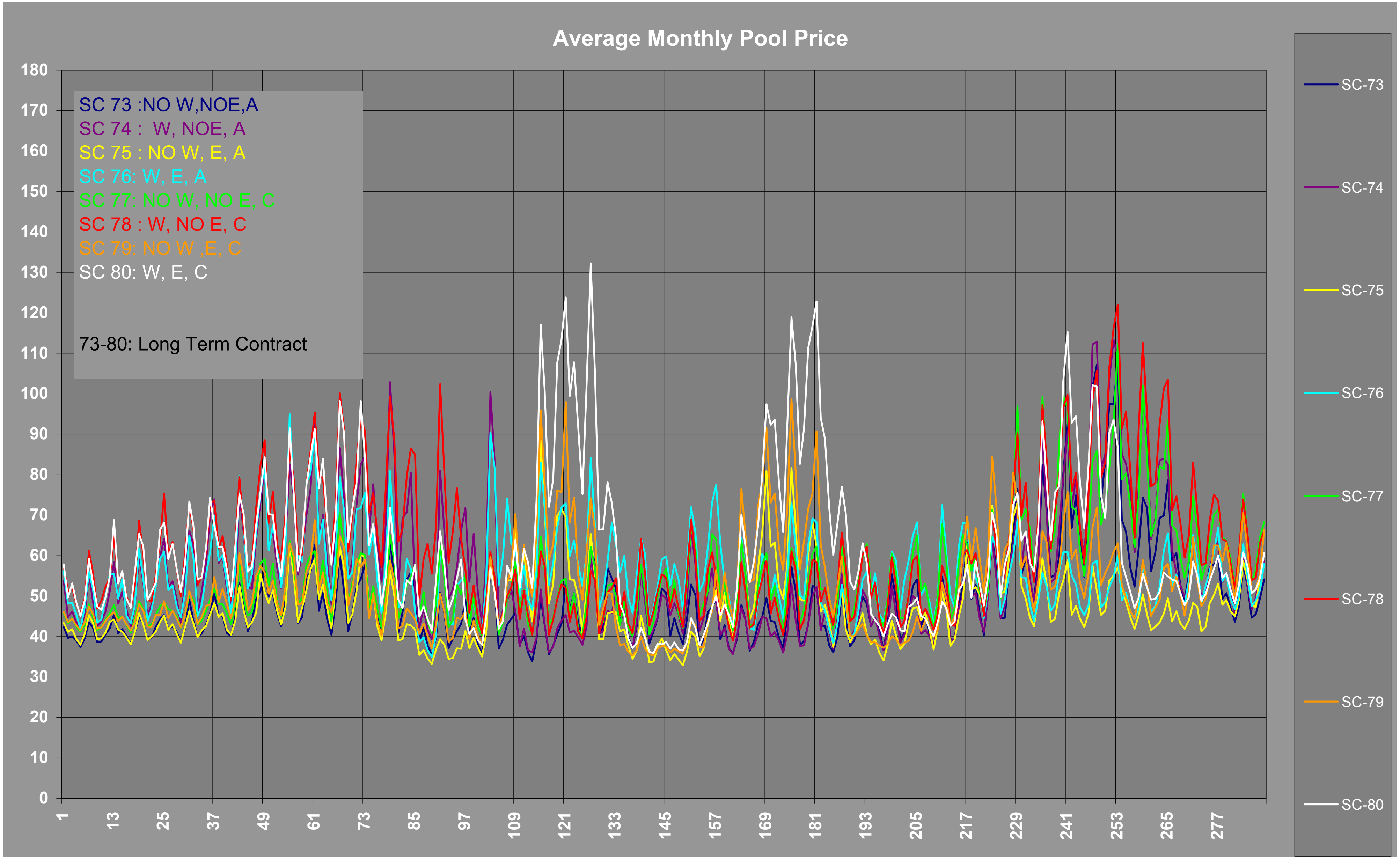

Average Monthly Pool Price
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
160
170
180
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277


Average Monthly Pool Price
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

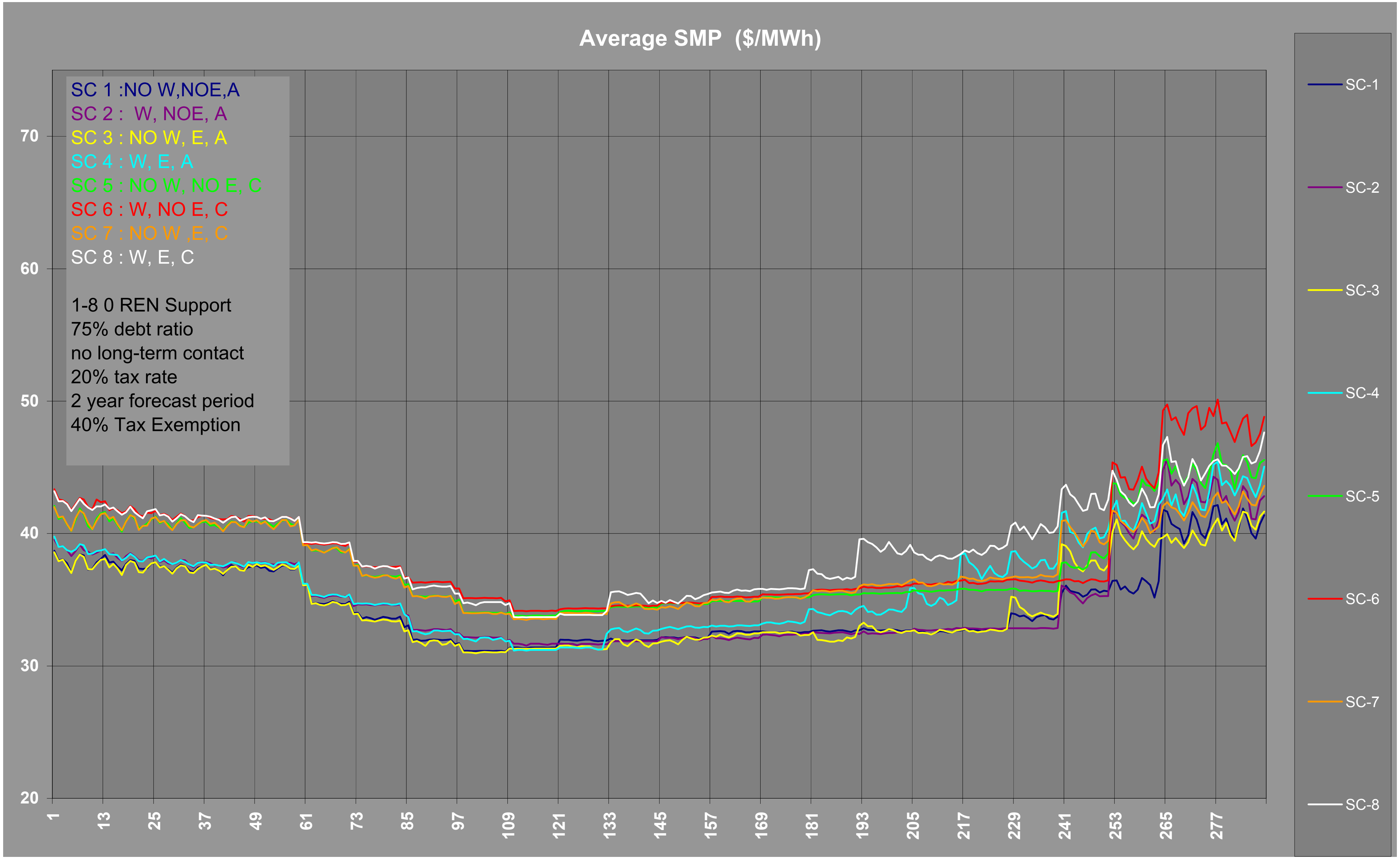

Average Monthly Pool Price
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48

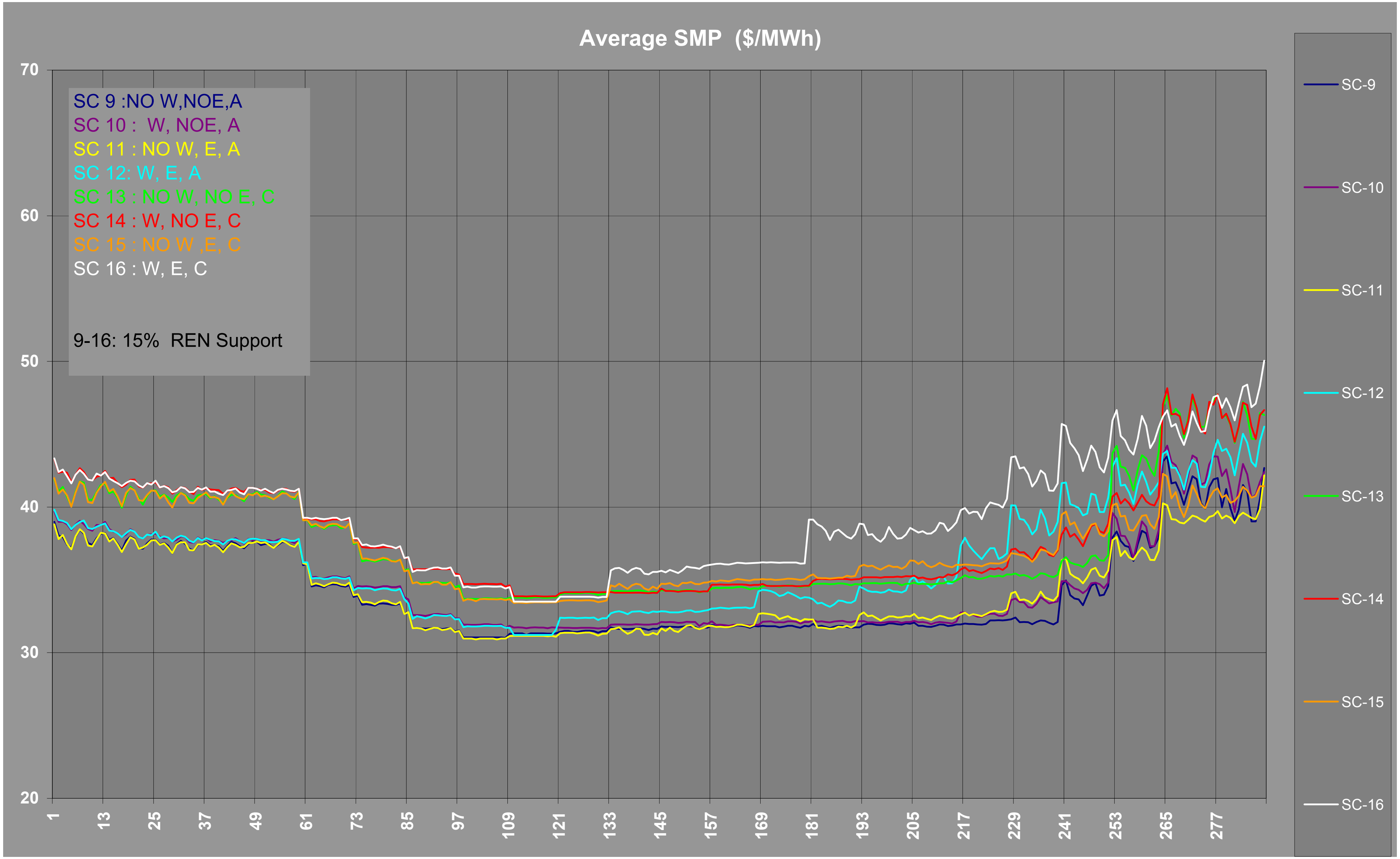


Average Monthly Pool Price
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

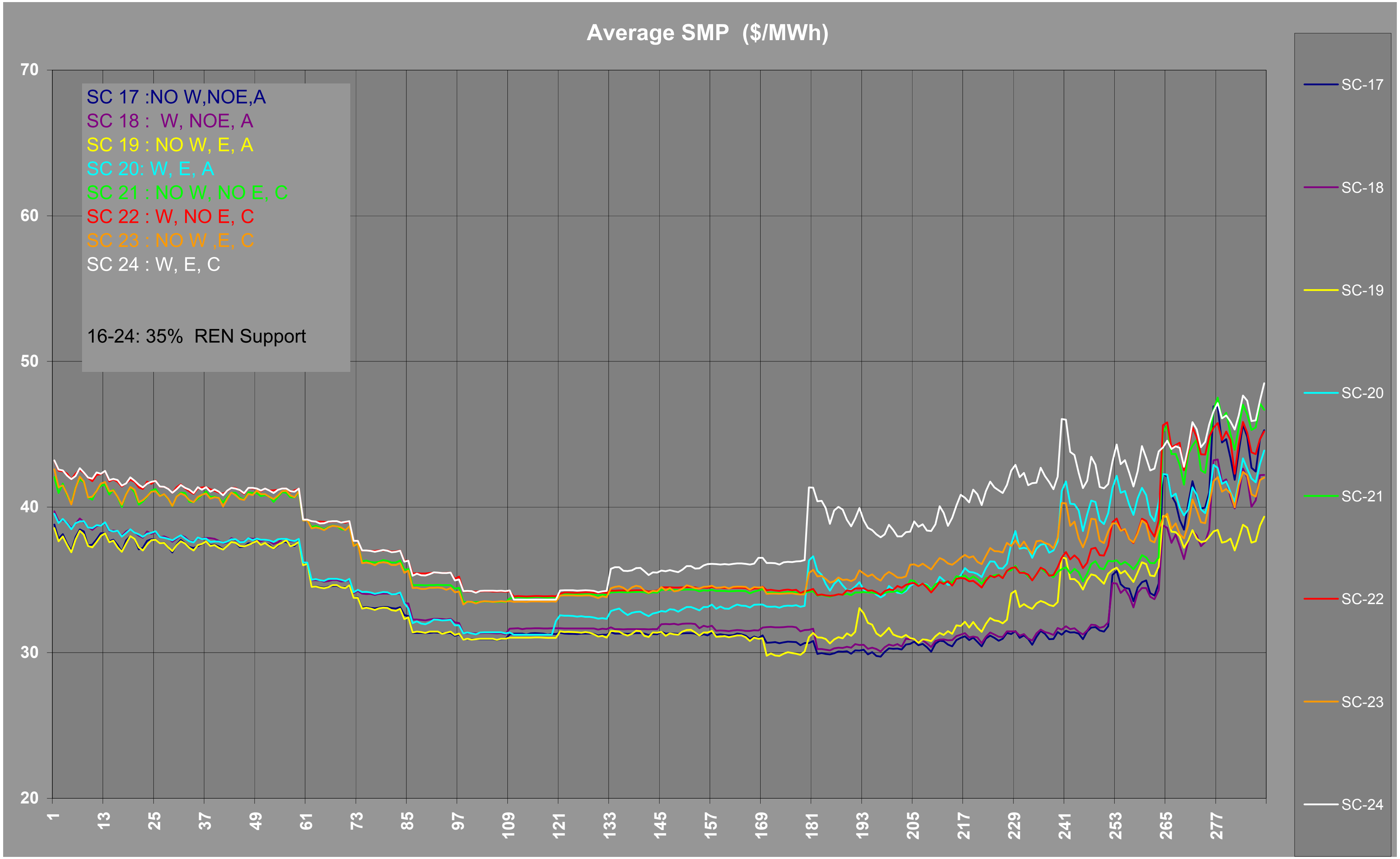


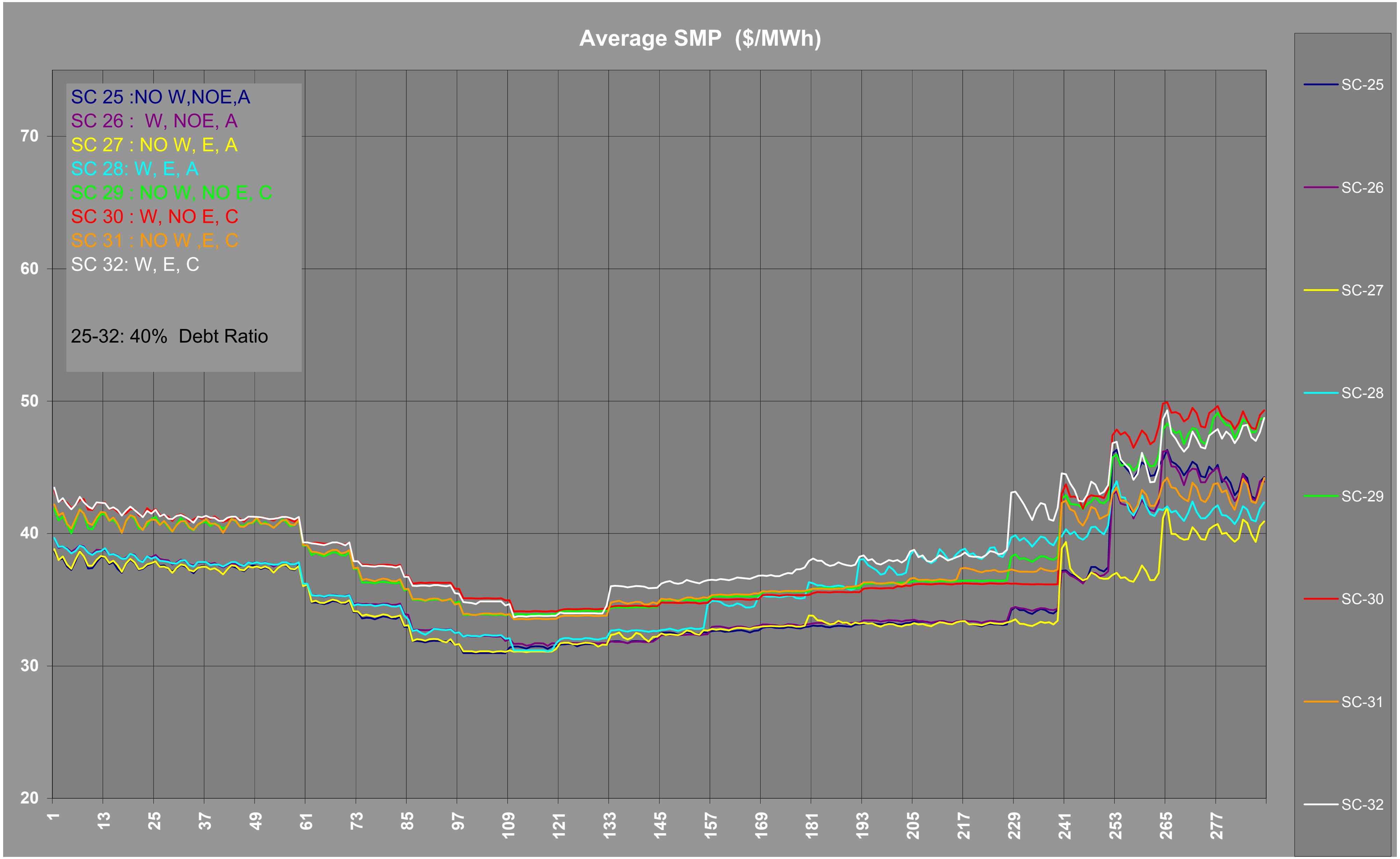
Average Monthly Pool Price
180
170
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80


Average SMP ($/MWh)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
70
60
50
40
30
20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

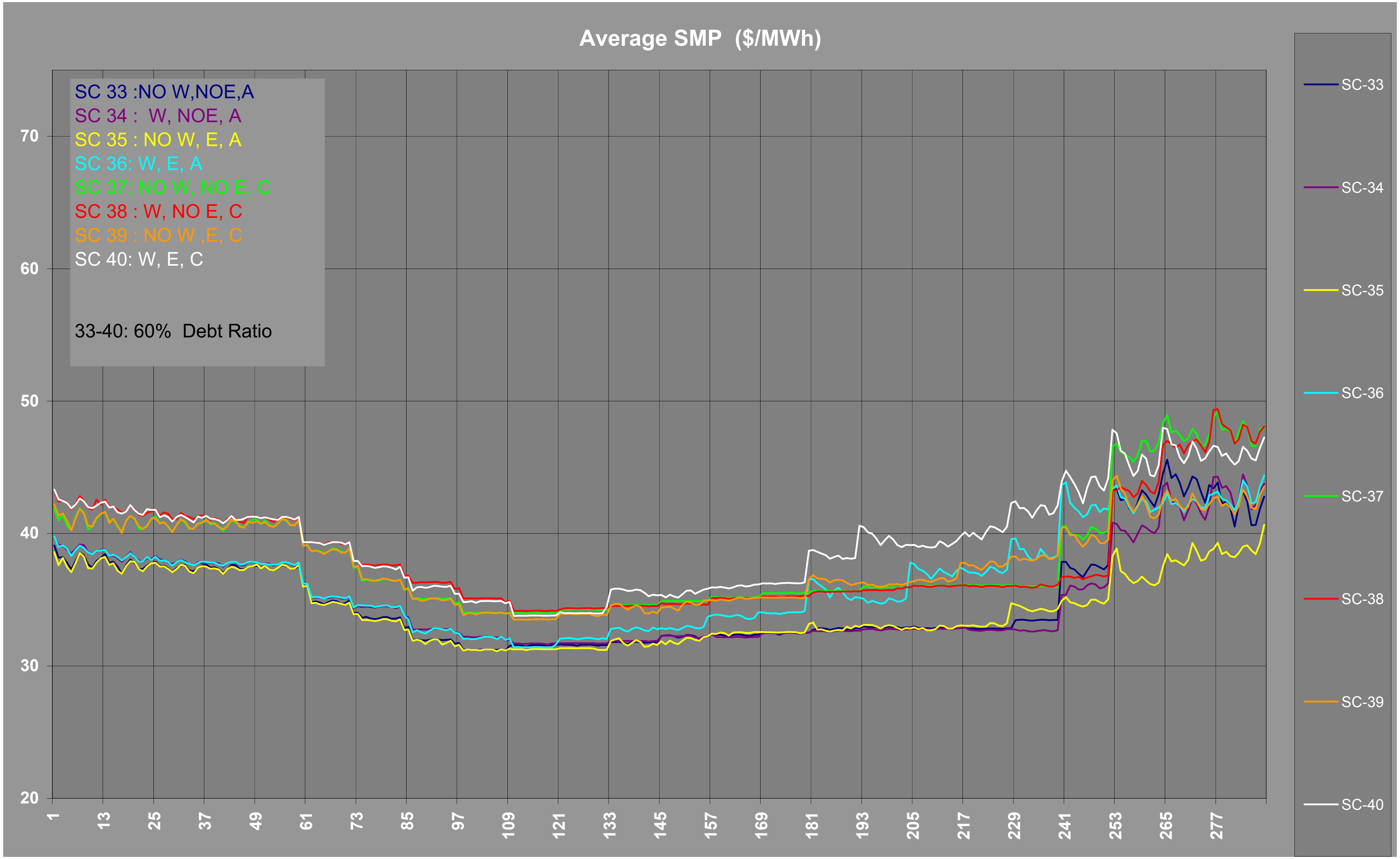


Average SMP ($/MWh)
70
60
50
40
30
20
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16

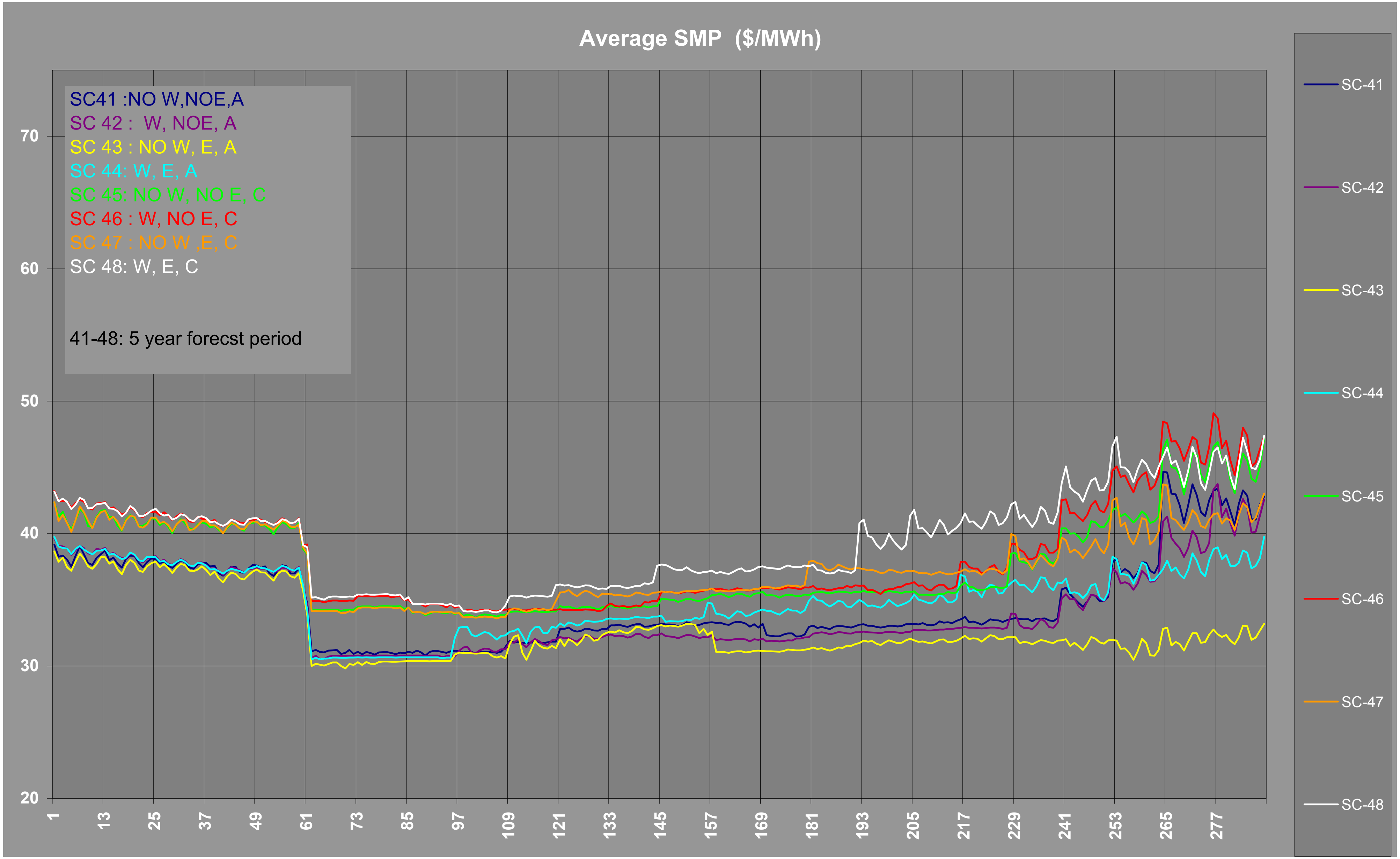

Average SMP ($/MWh)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
16-24: 35% REN Support
70
60
50
40
30
20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24

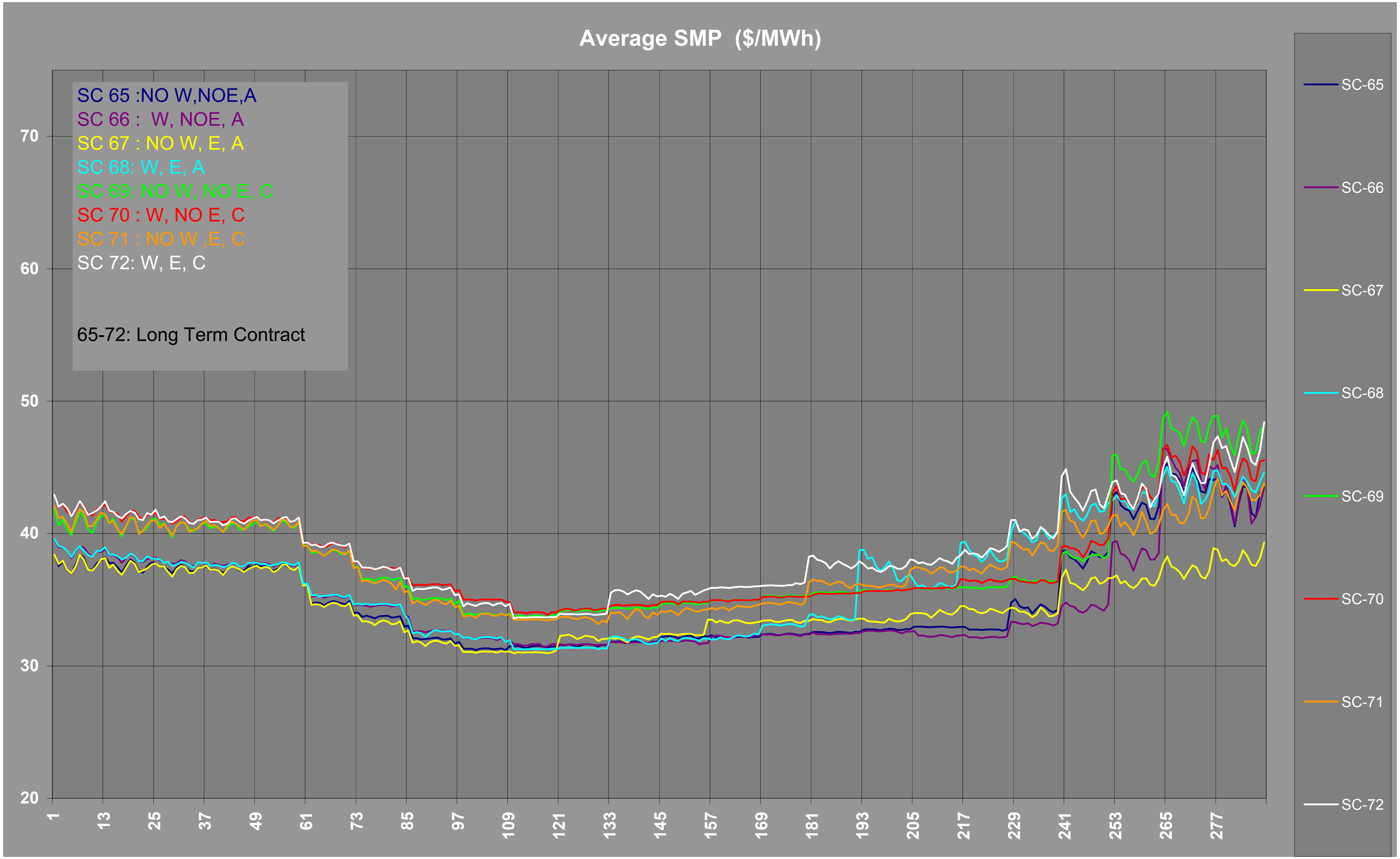


Average SMP ($/MWh)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
70
60
50
40
30
20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32

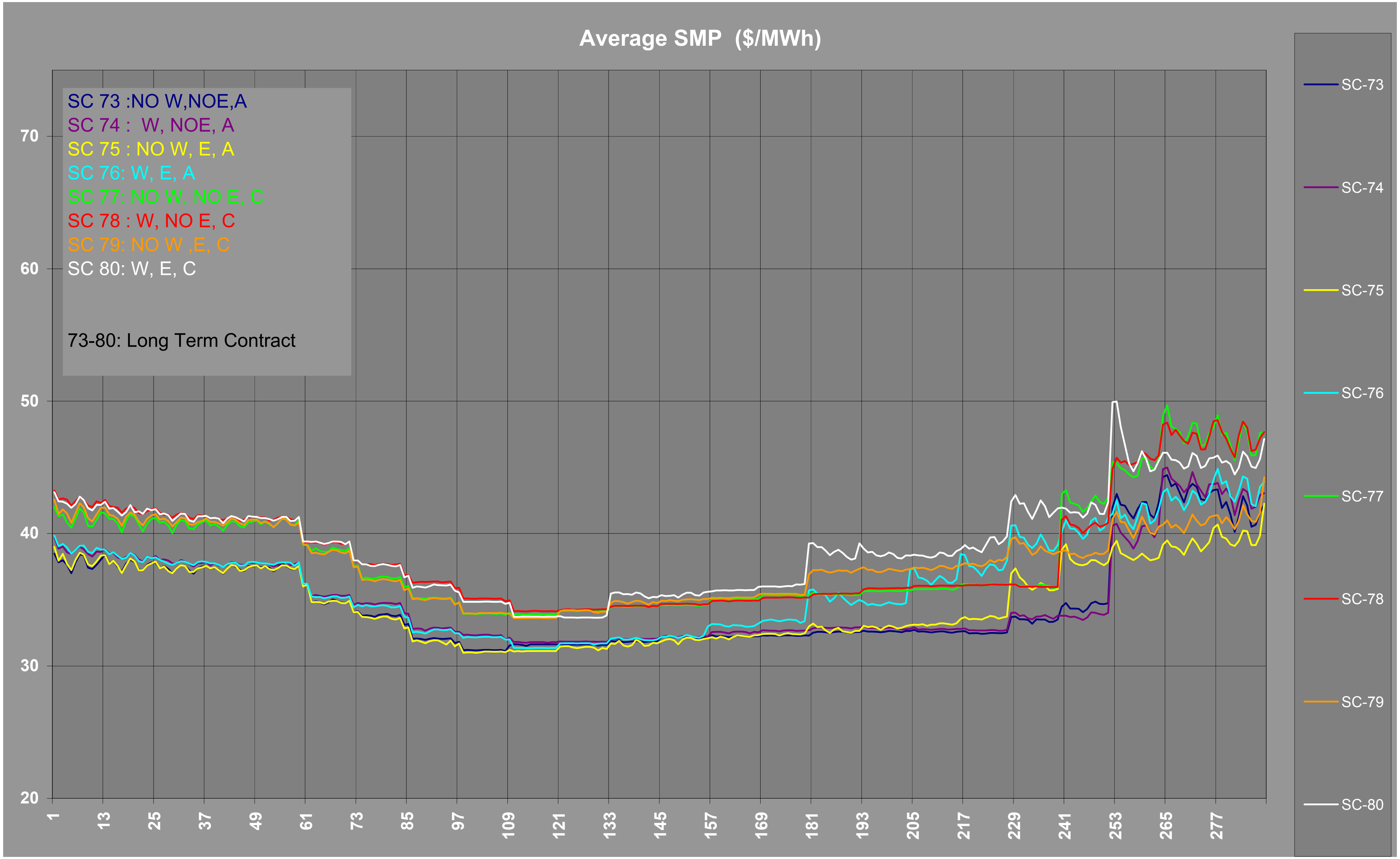


Average SMP ($/MWh)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
70
60
50
40
30
20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

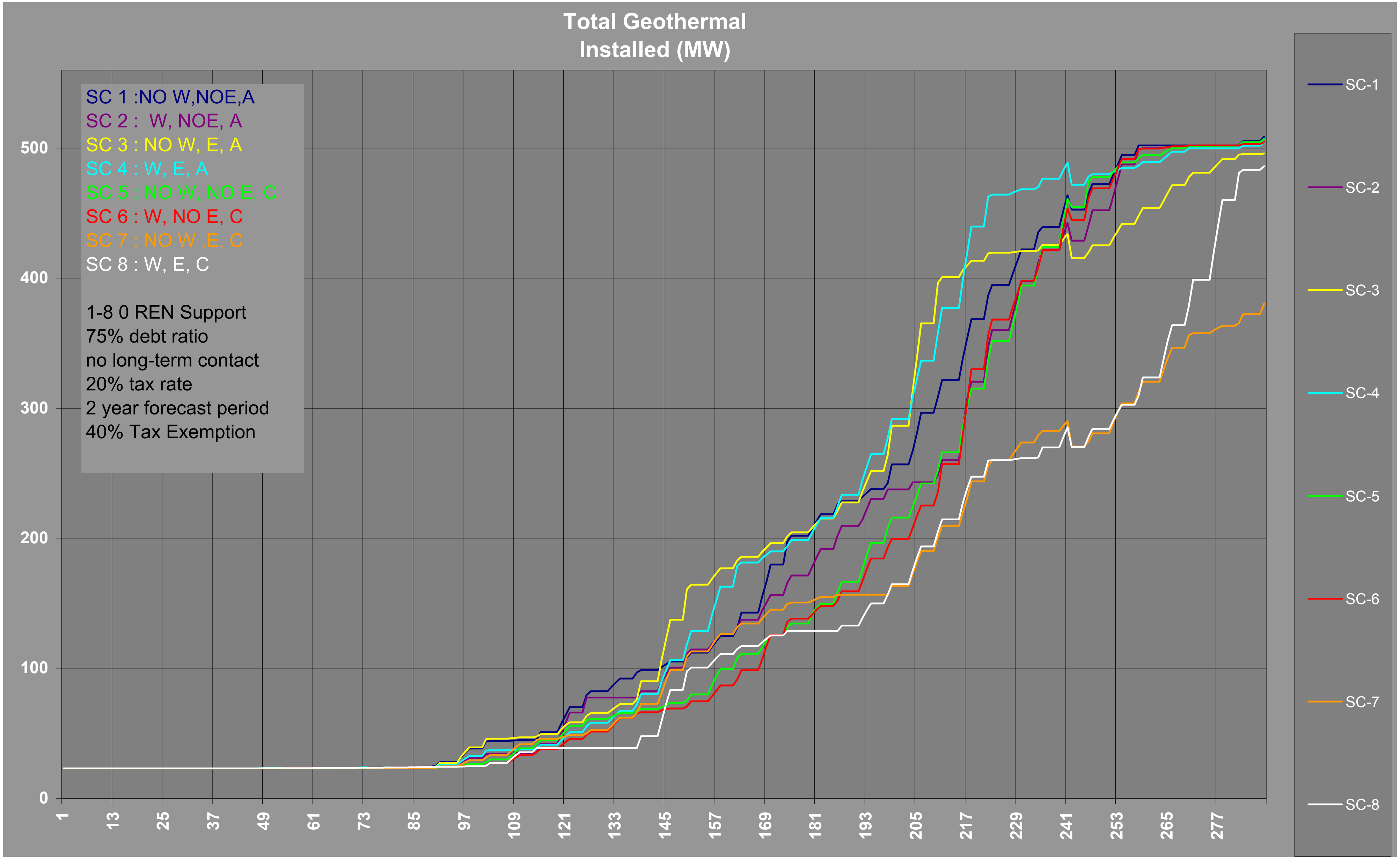

Average SMP ($/MWh)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
70
60
50
40
30
20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



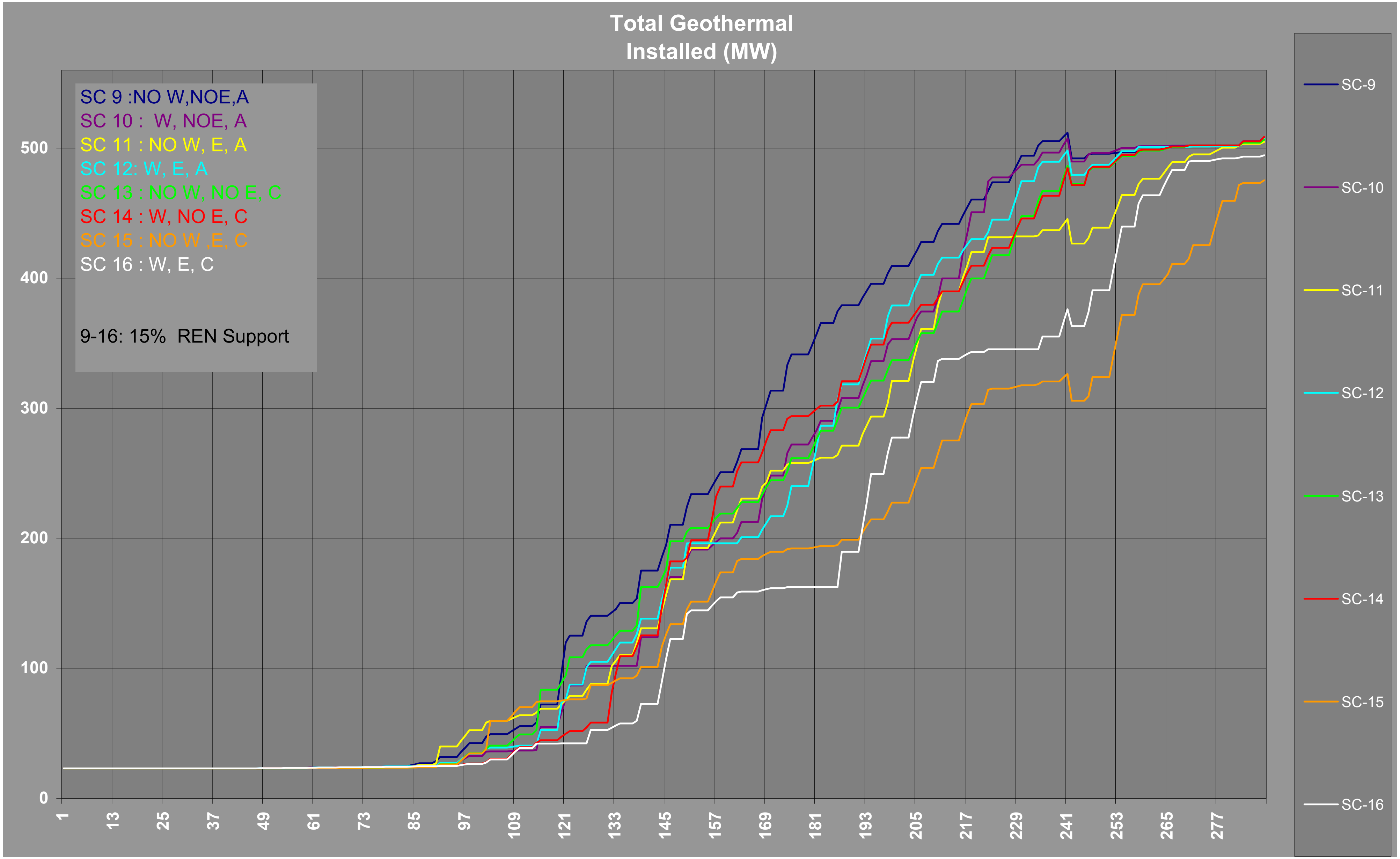
Average SMP ($/MWh)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
70
60
50
40
30
20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

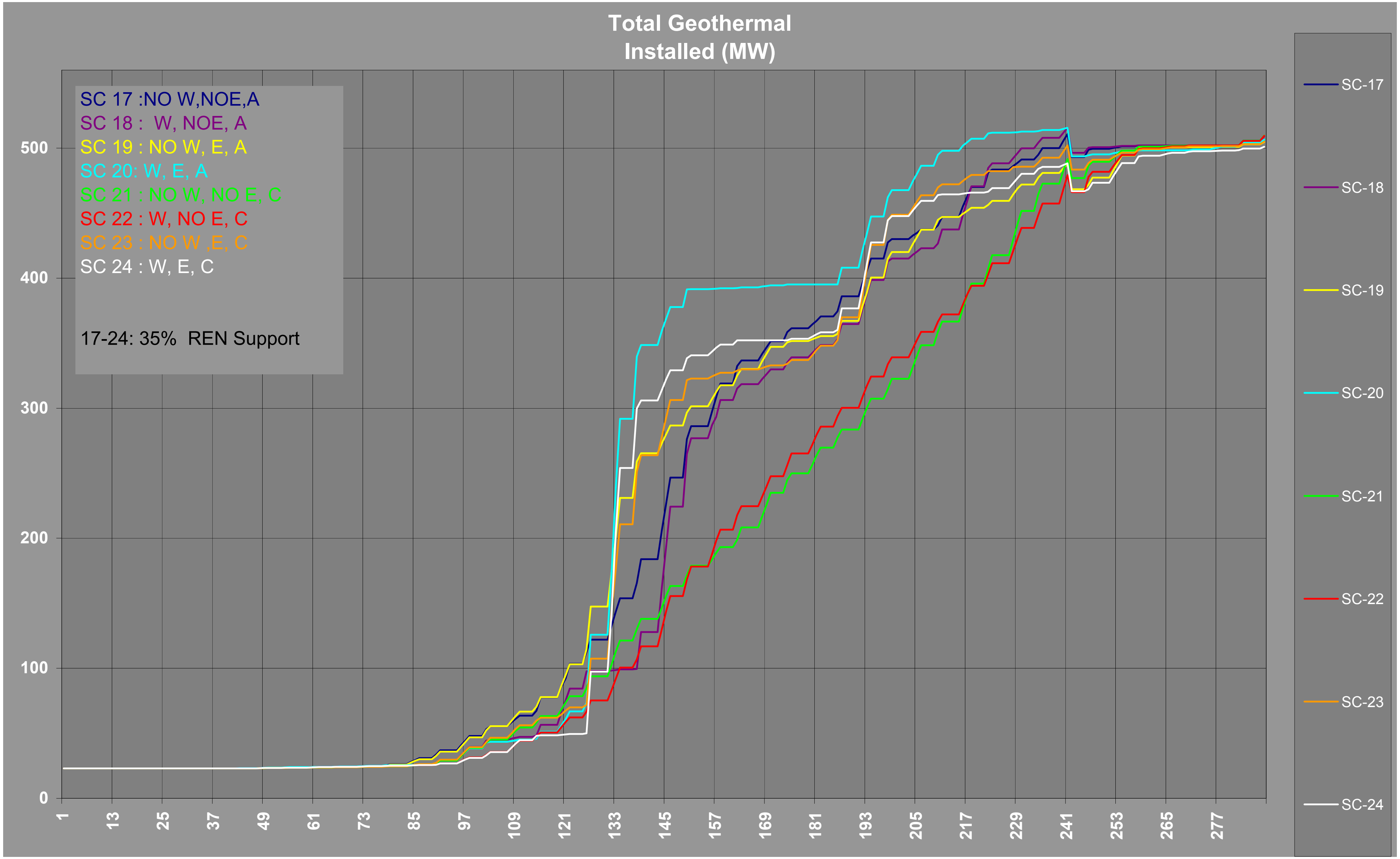


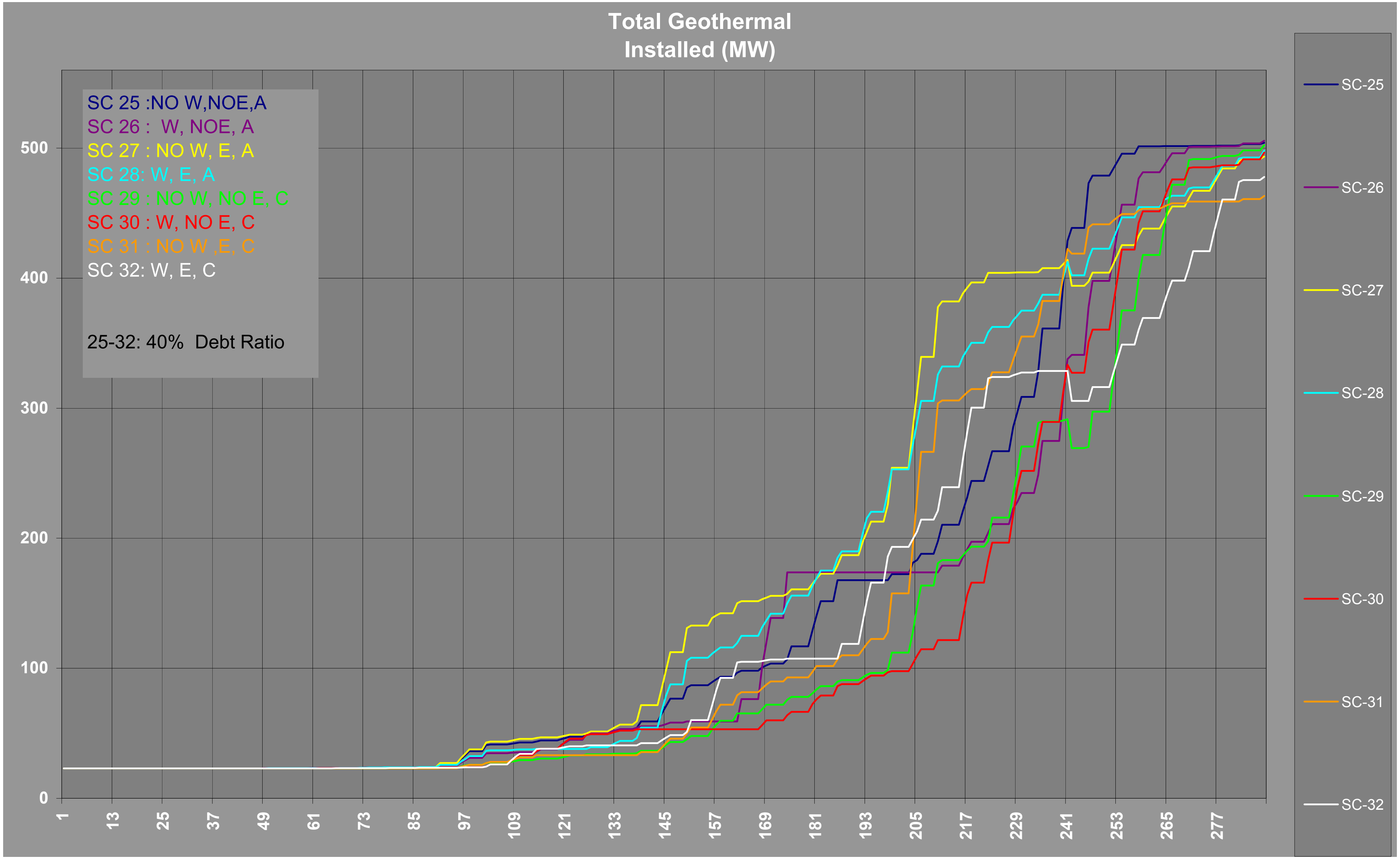
Average SMP ($/MWh)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
70
60
50
40
30
20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

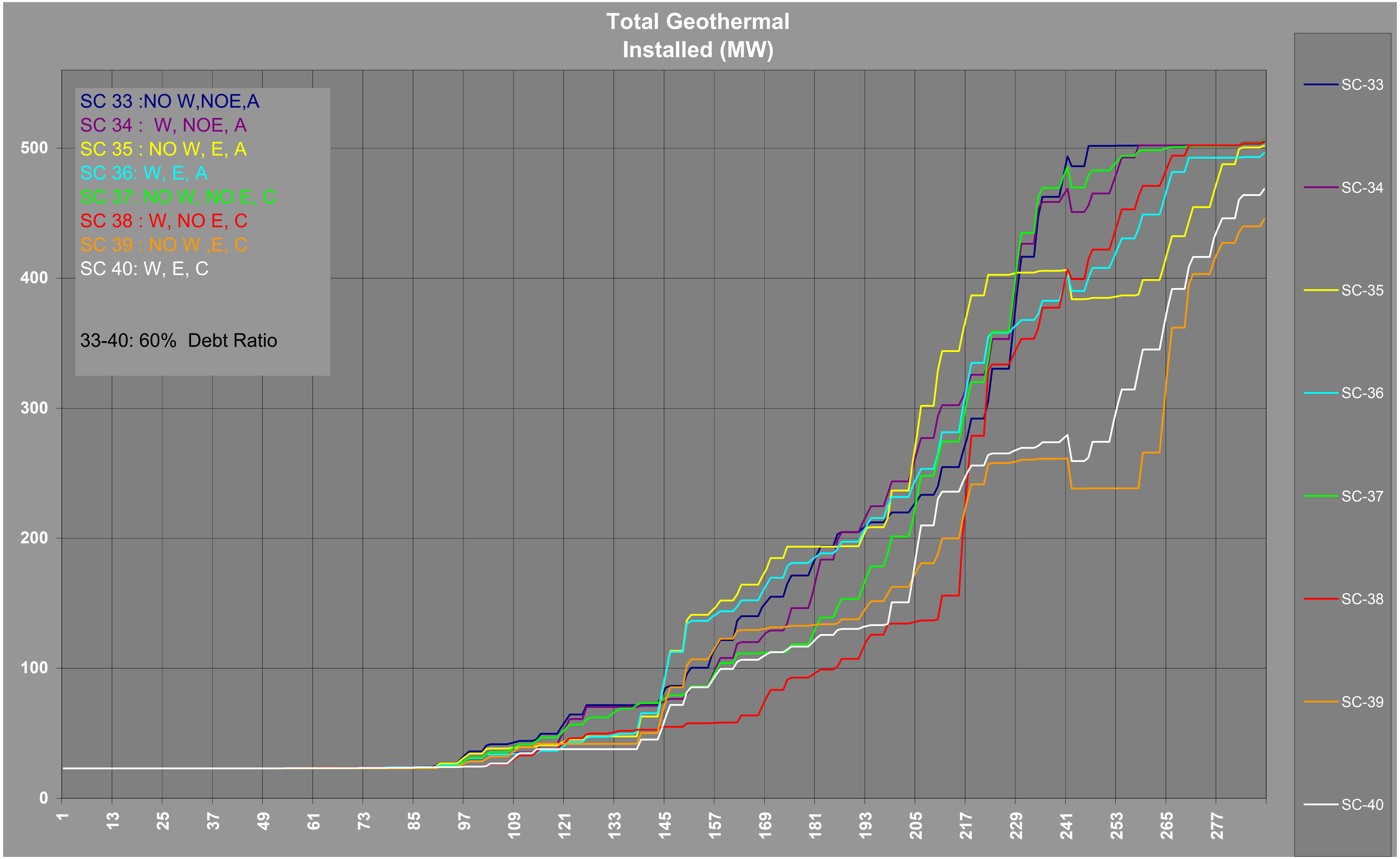


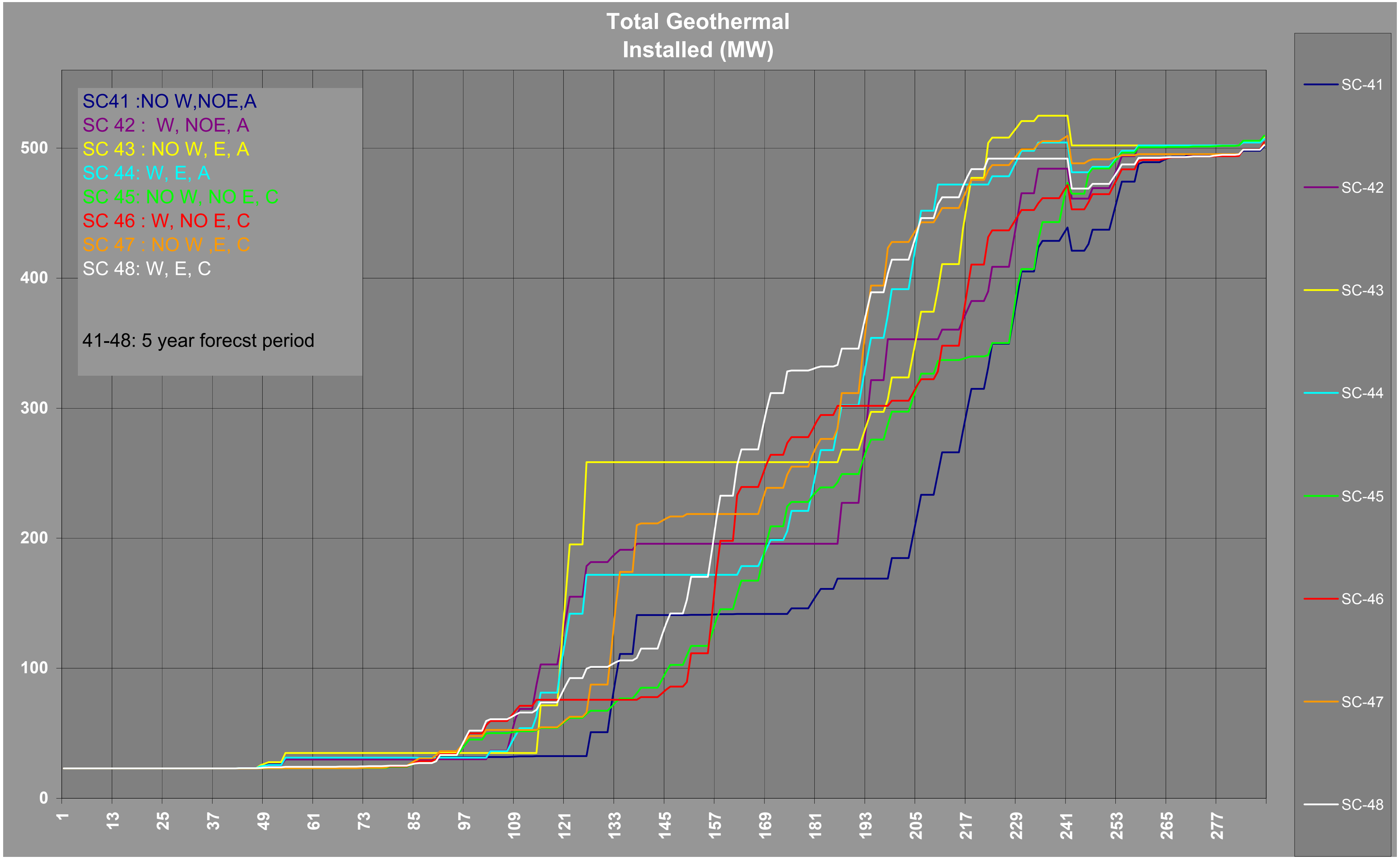
Total Geothermal
Installed (MW)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
0
100
200
300
400
500
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

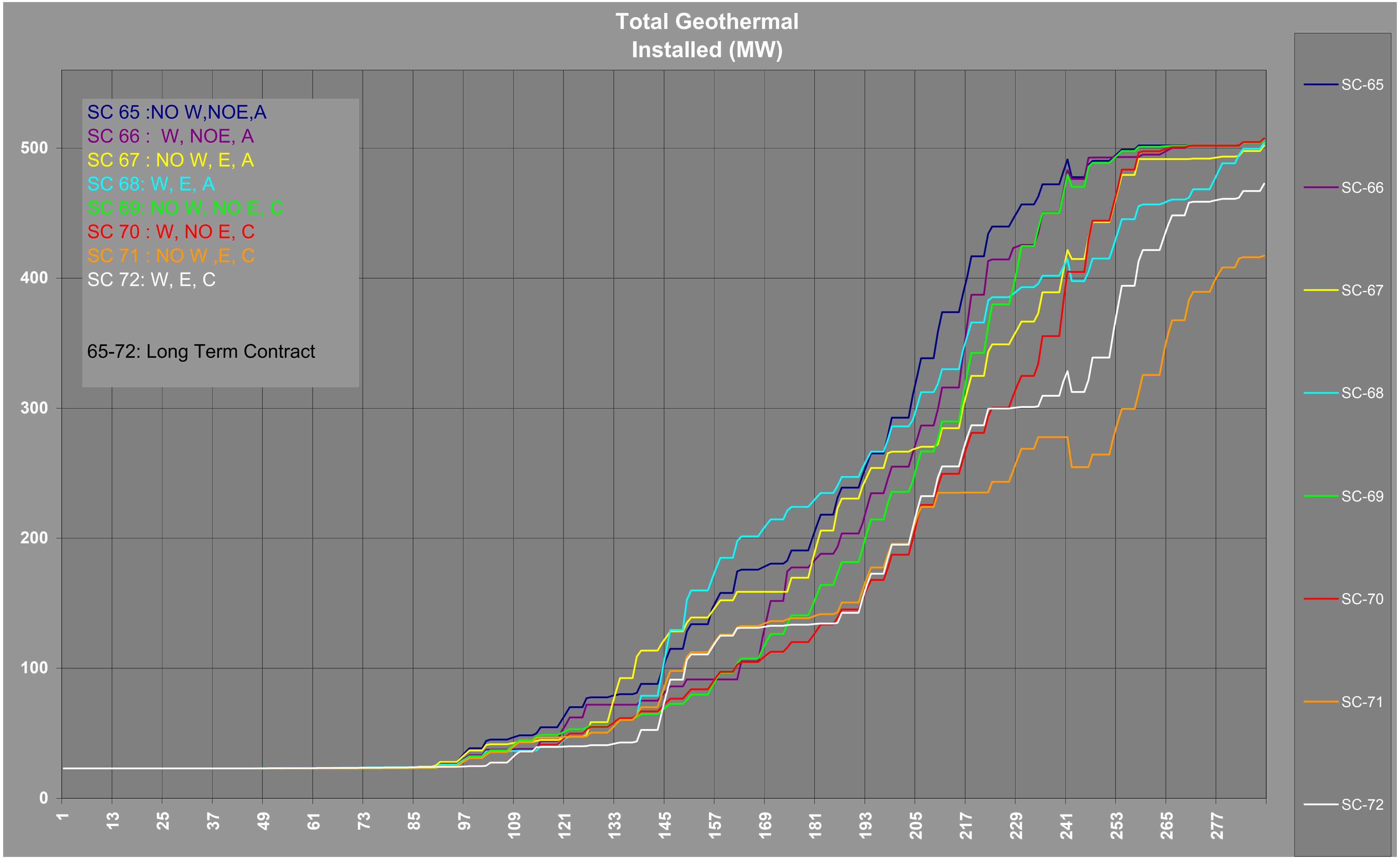

Total Geothermal
Installed (MW)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
500
400
300
200
100
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16


Total Geothermal
Installed (MW)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
0
100
200
300
400
500
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24

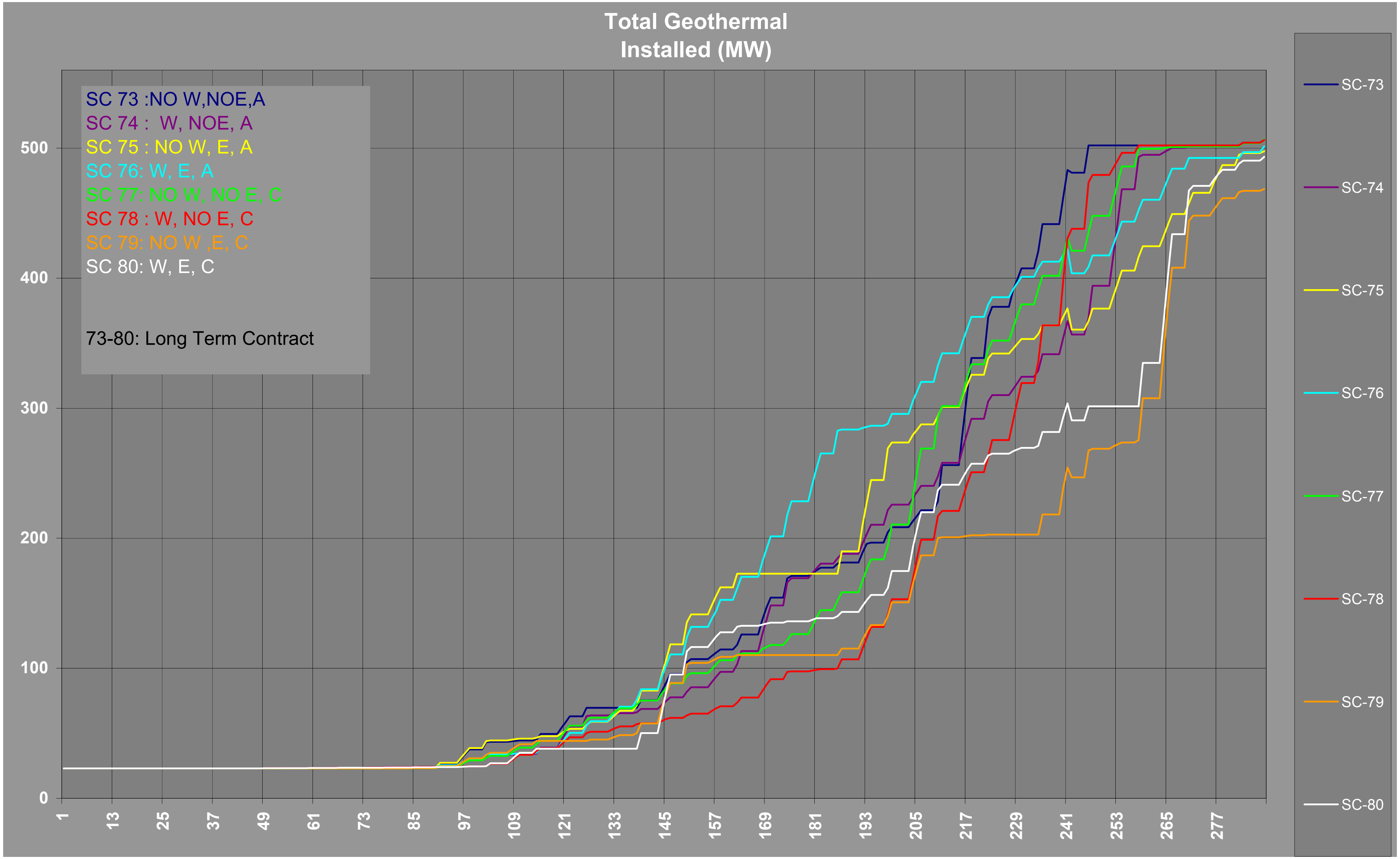

Total Geothermal
Installed (MW)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32
0
100
200
300
400
500
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277


Total Geothermal
Installed (MW)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40
0
100
200
300
400
500
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277


Total Geothermal
Installed (MW)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
0
100
200
300
400
500
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



Total Geothermal
Installed (MW)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
500
400
300
200
100
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



Total Geothermal
Installed (MW)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
500
400
300
200
100
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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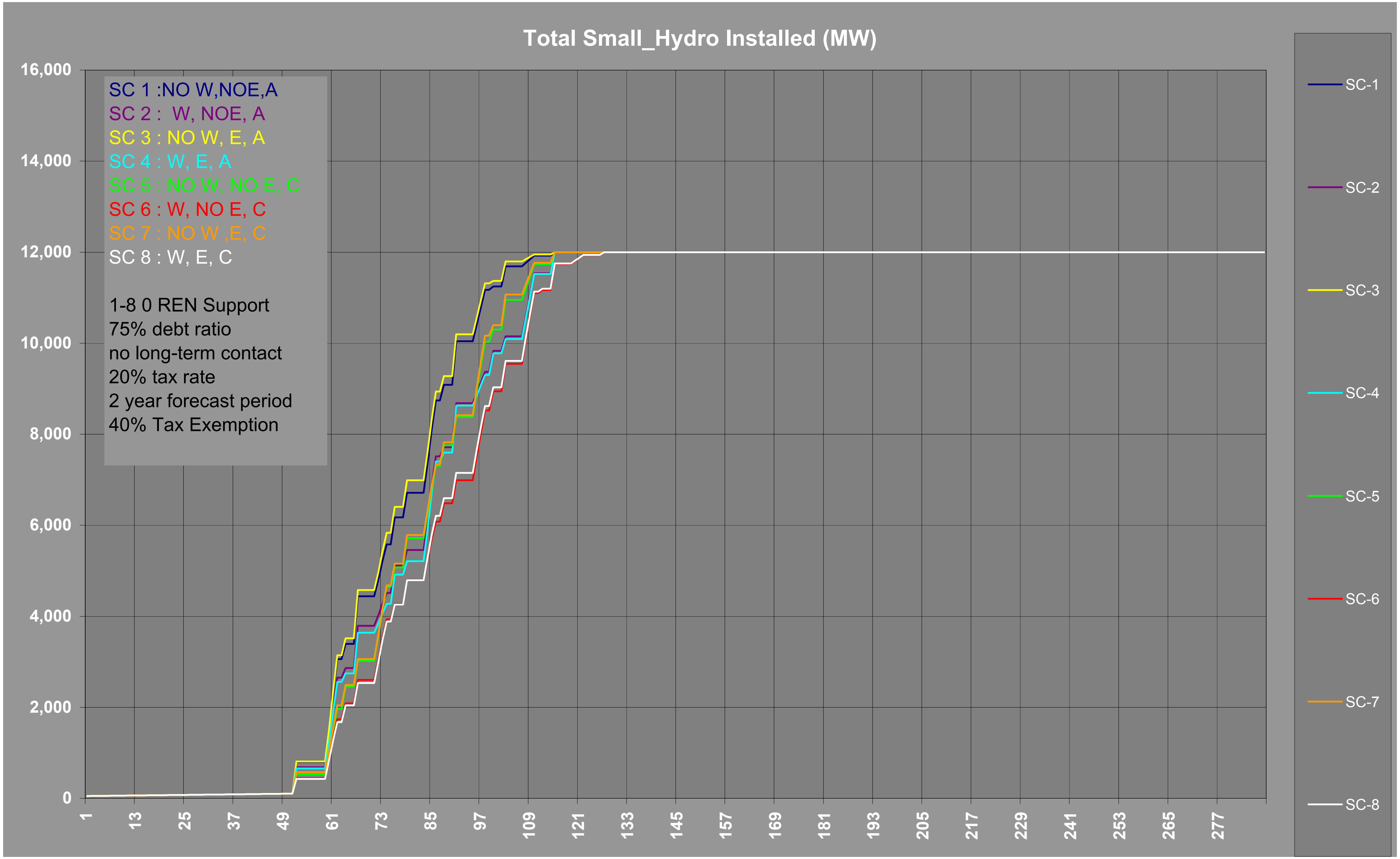
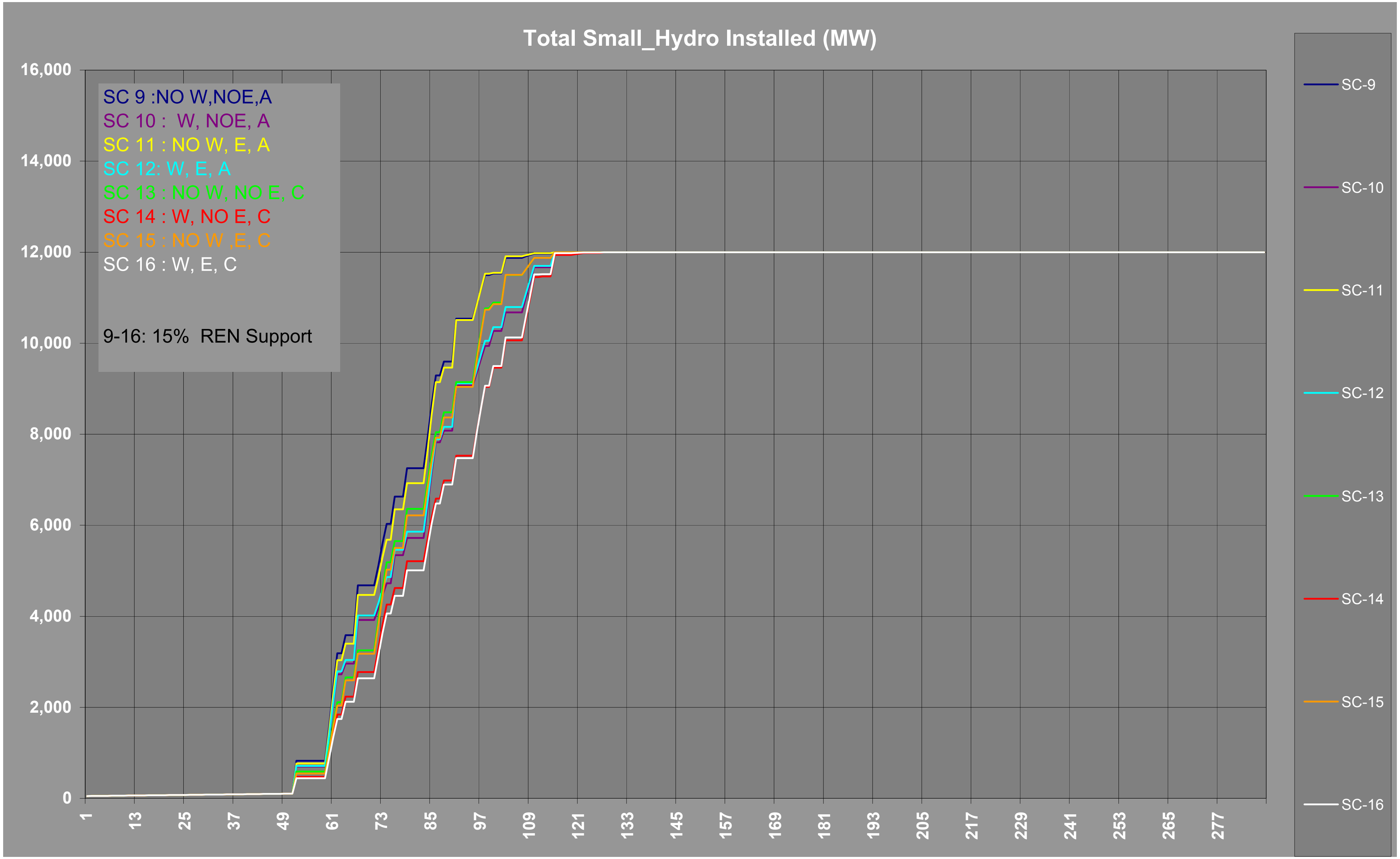
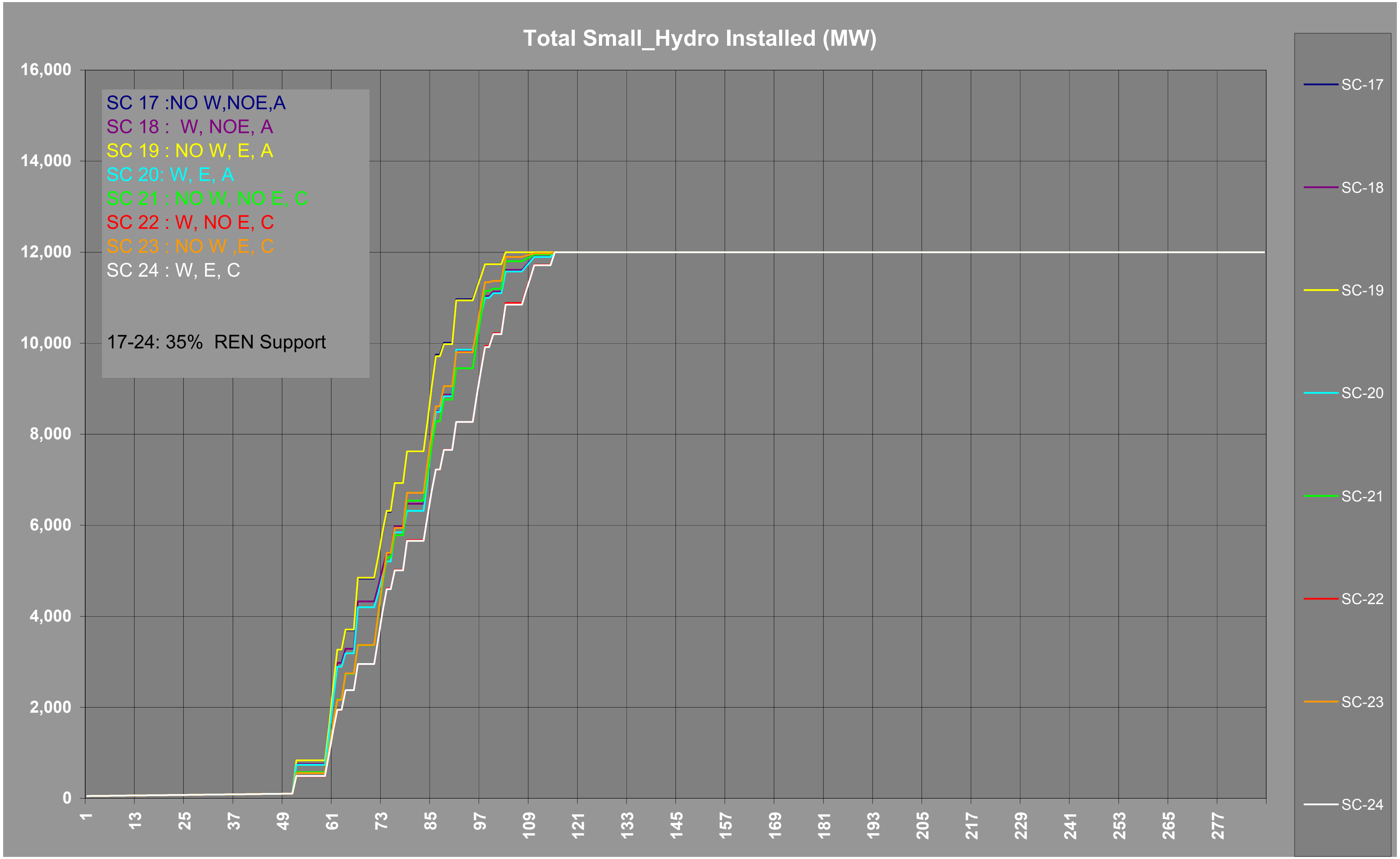
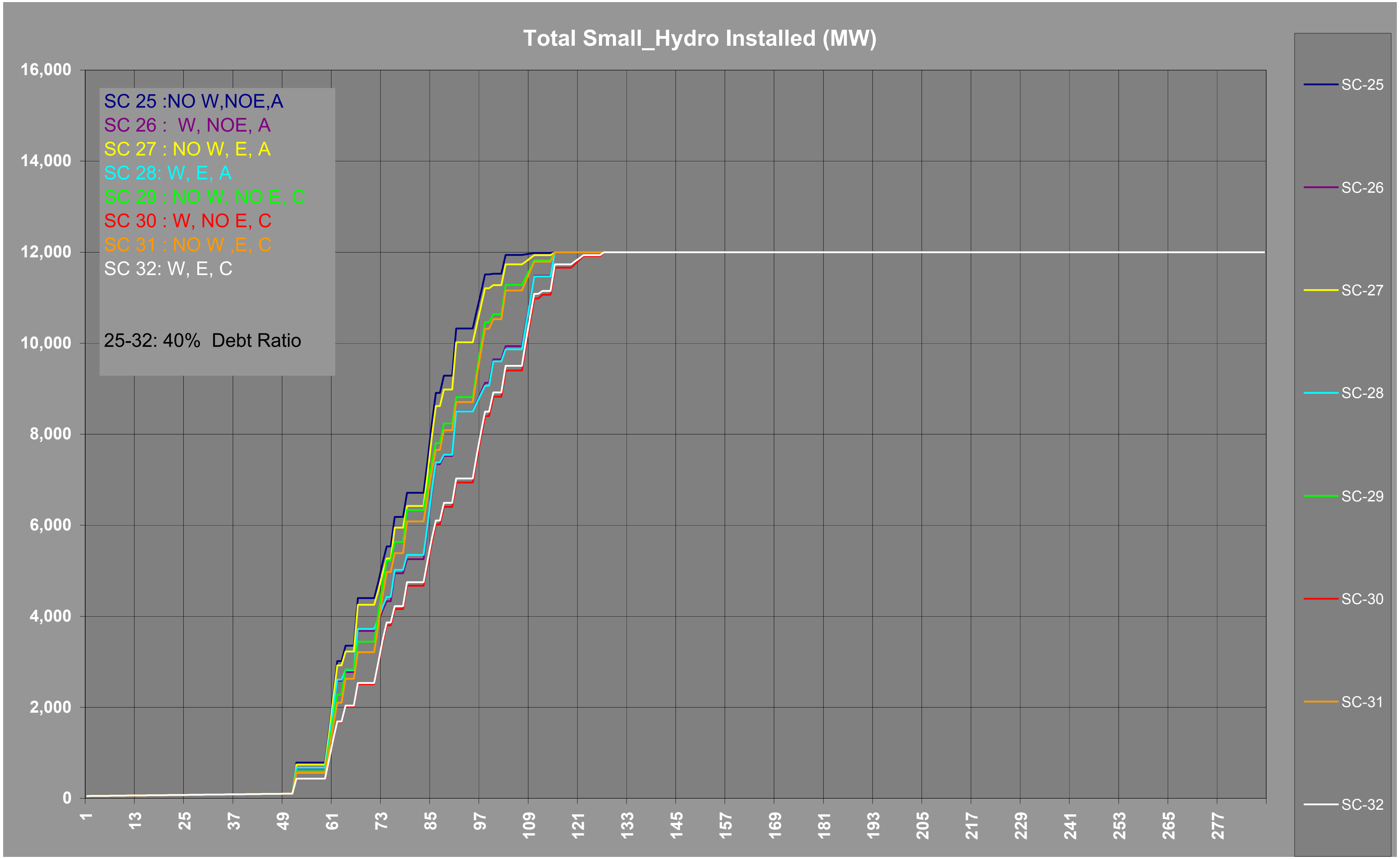
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80


Total Small_Hydro Installed (MW)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

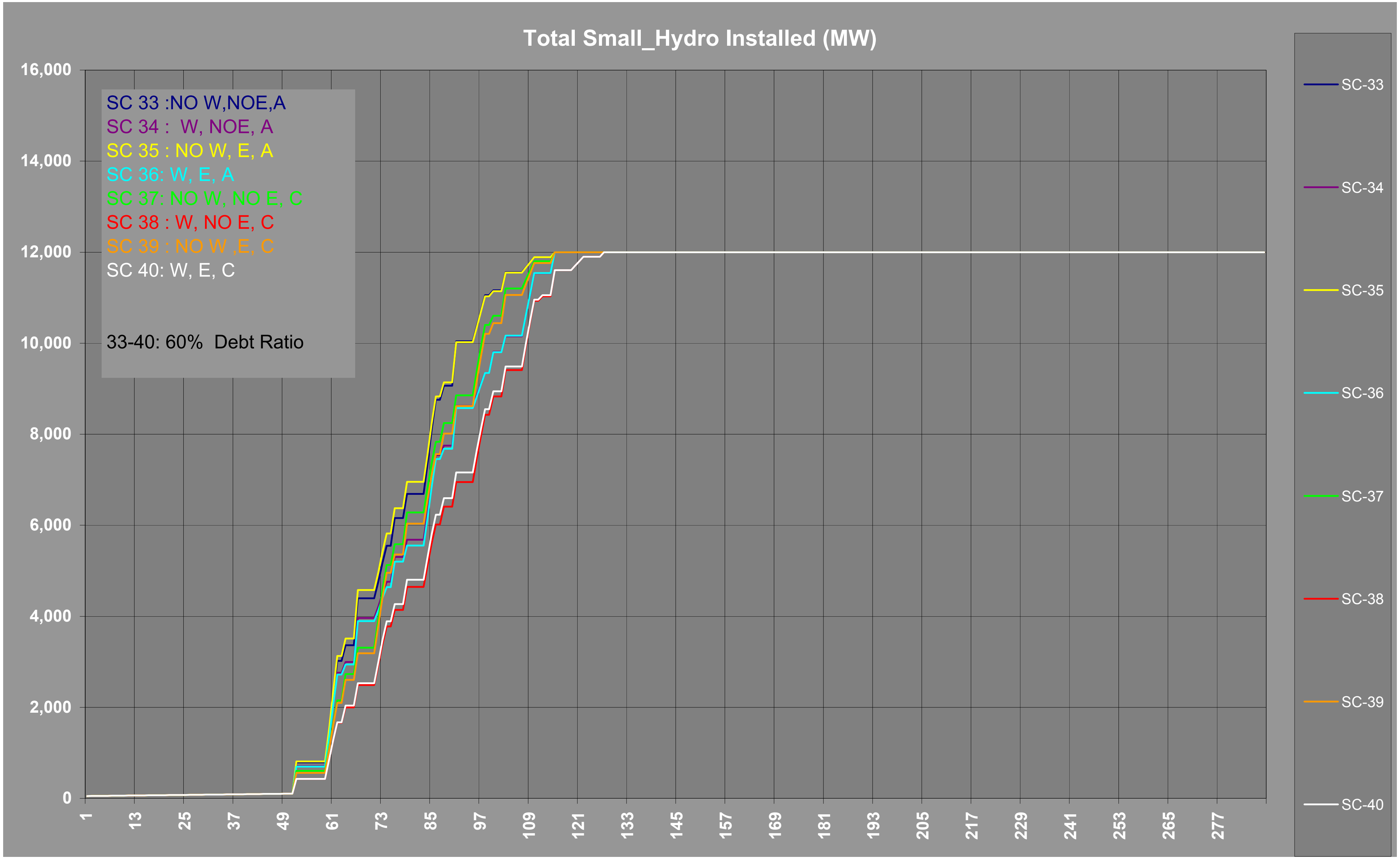


Total Small_Hydro Installed (MW)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16

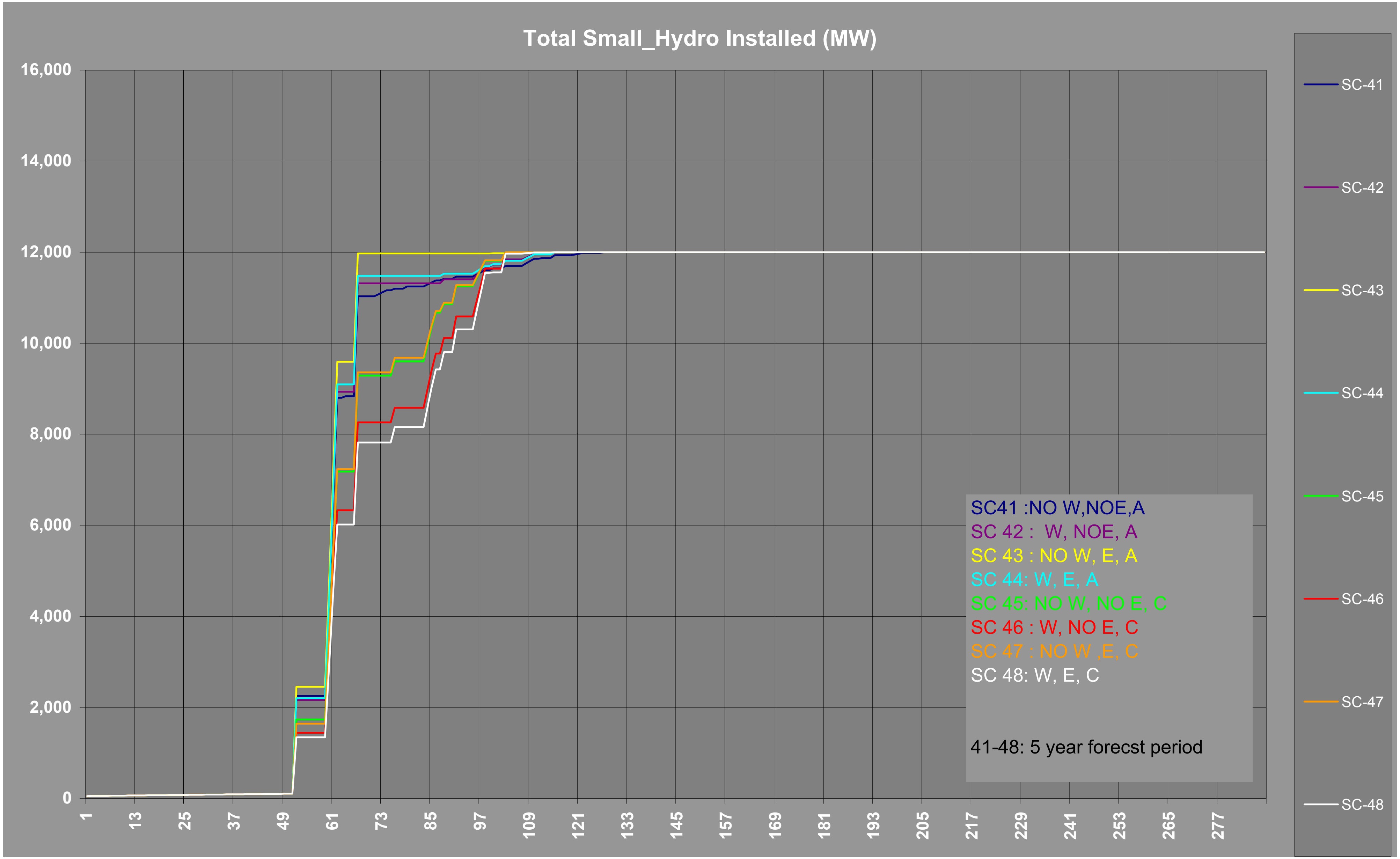

Total Small_Hydro Installed (MW)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24

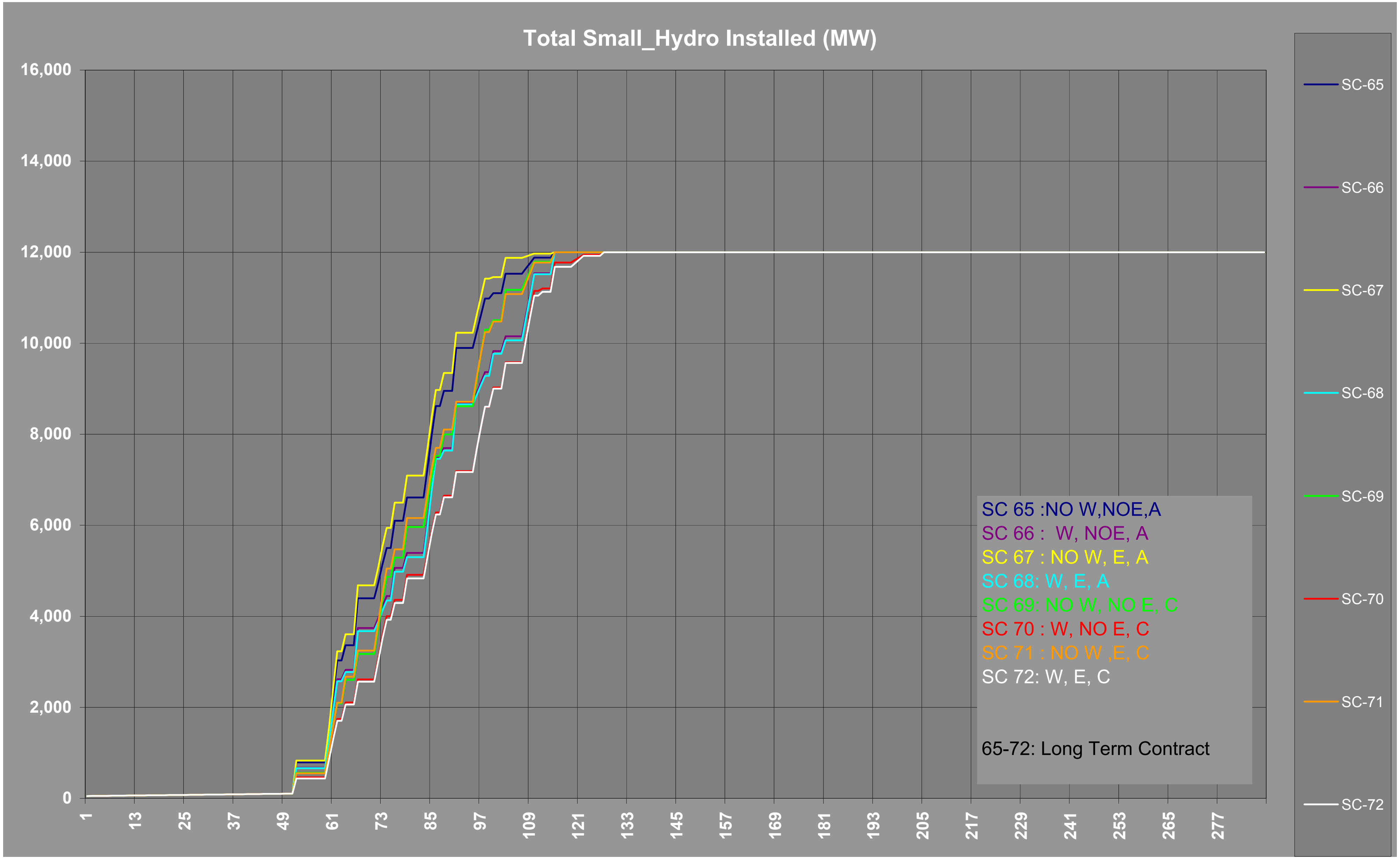


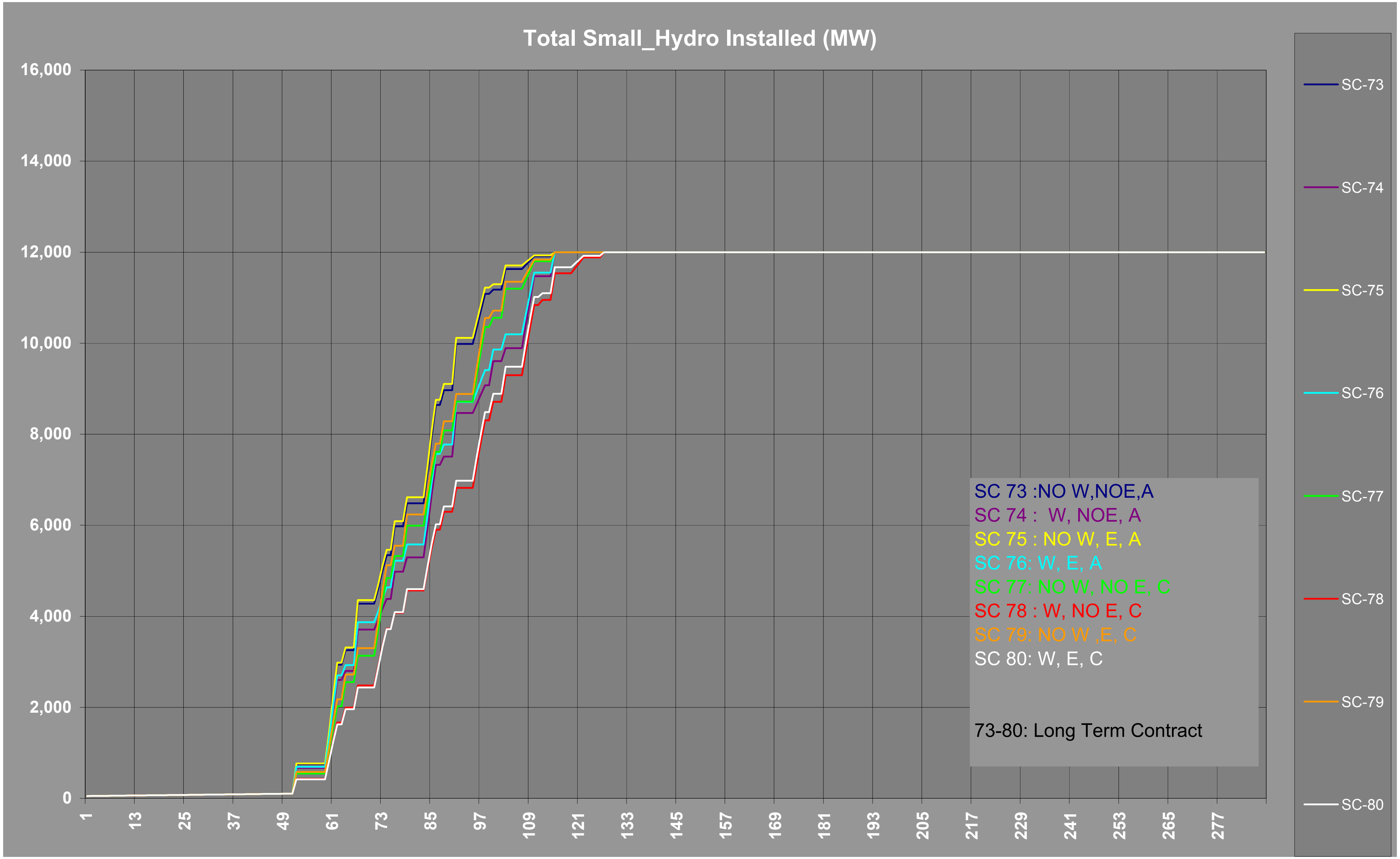
Total Small_Hydro Installed (MW)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



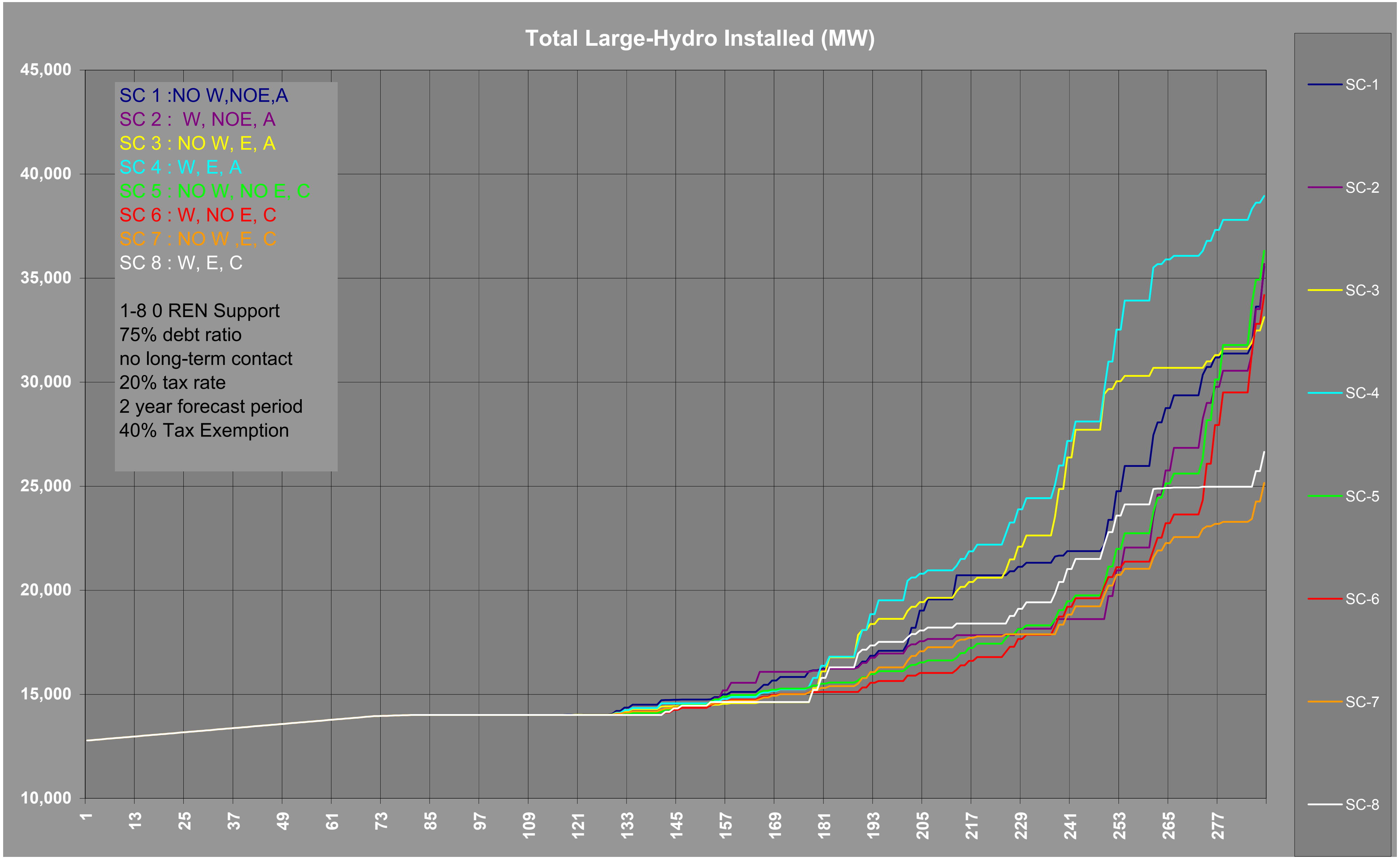
Total Small_Hydro Installed (MW)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40


Total Small_Hydro Installed (MW)
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period

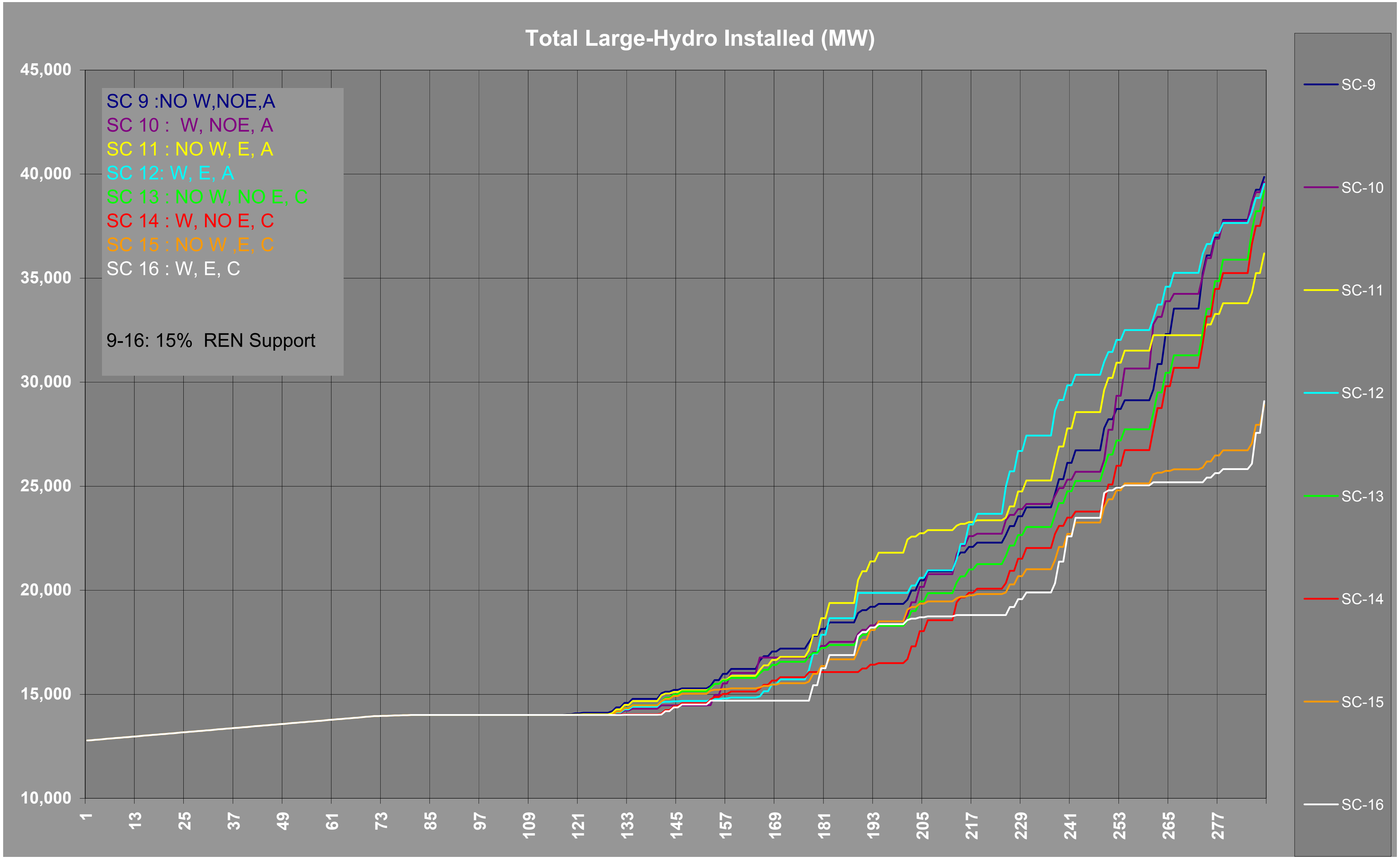

Total Small_Hydro Installed (MW)
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

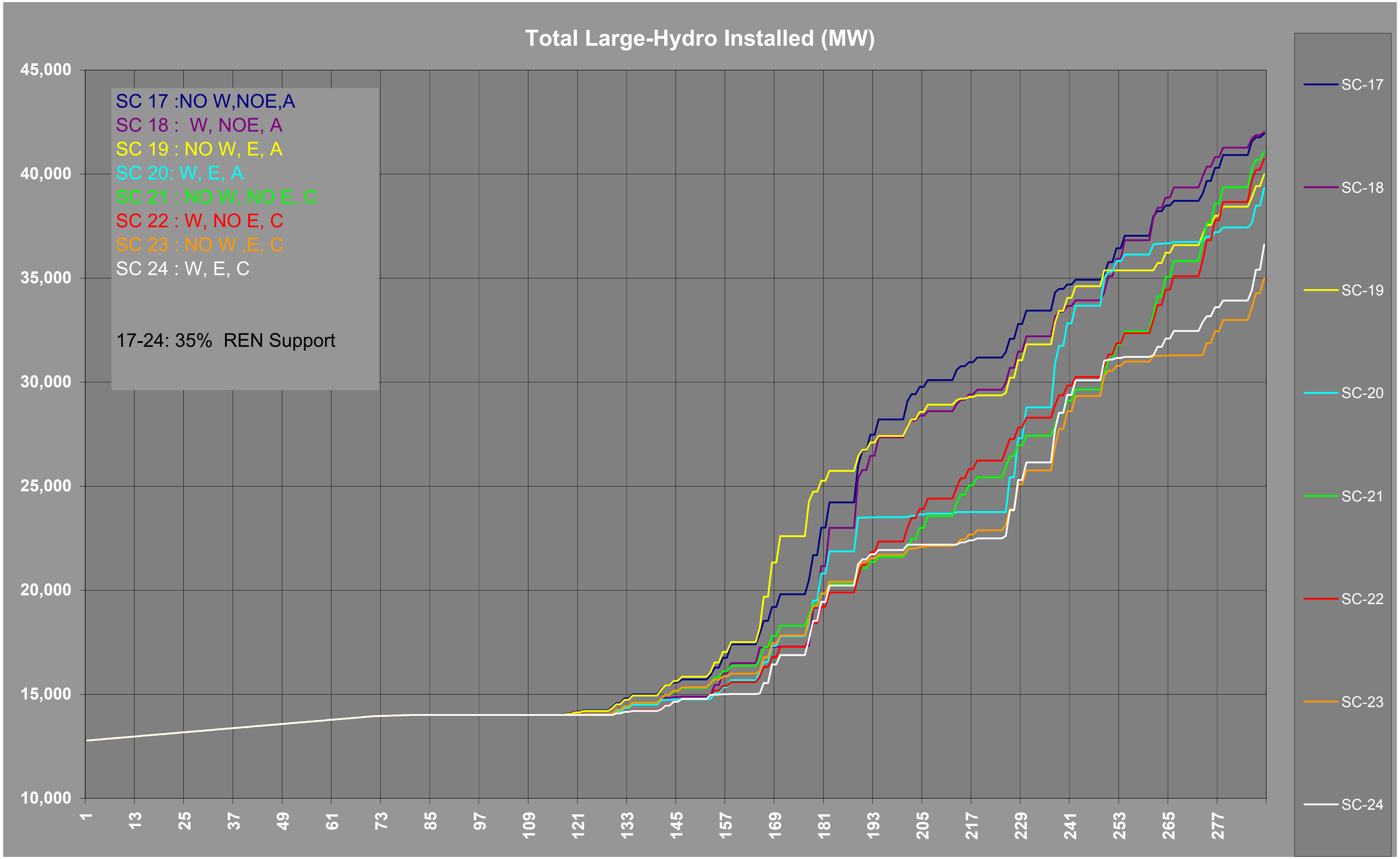


Total Small_Hydro Installed (MW)
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

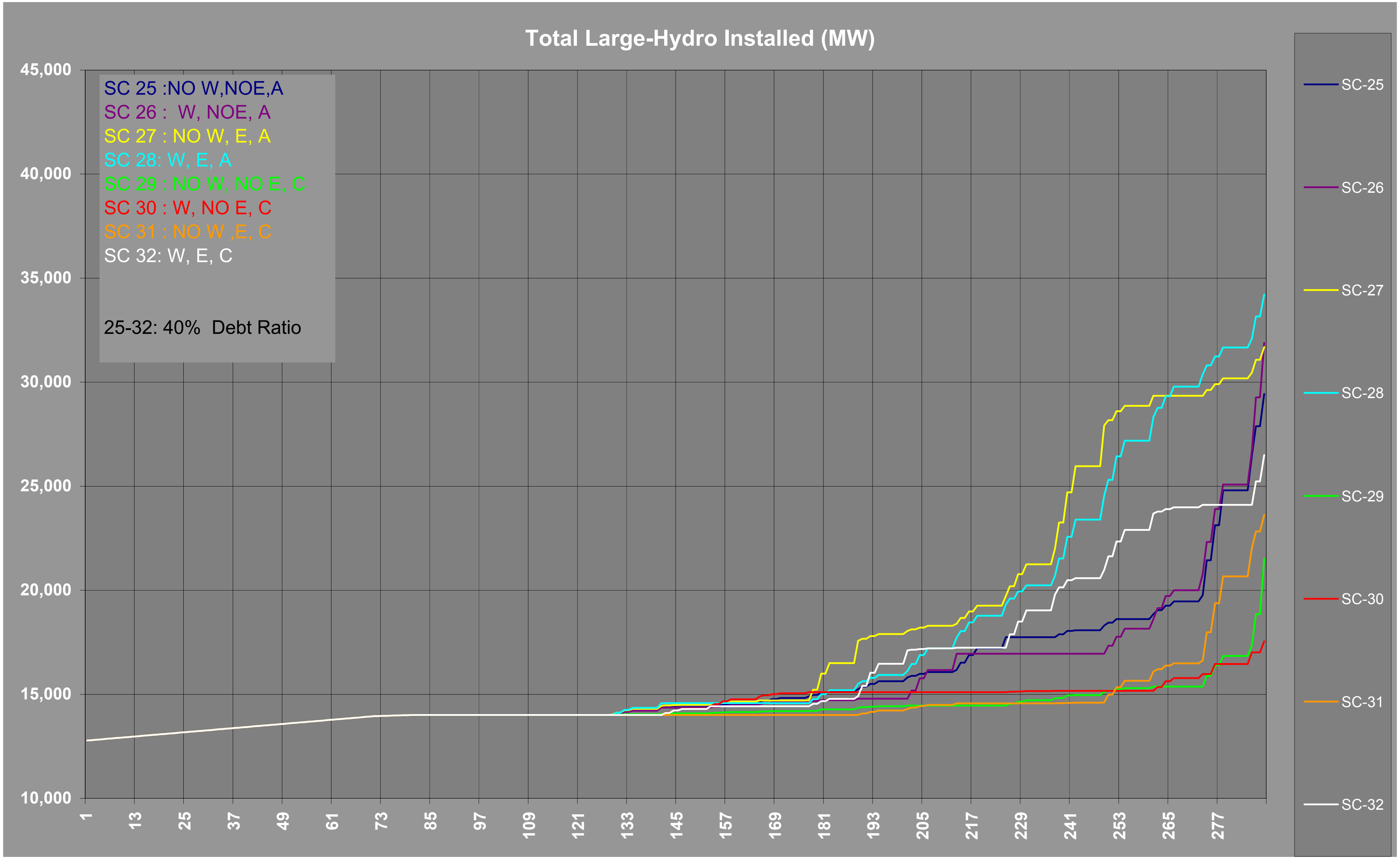


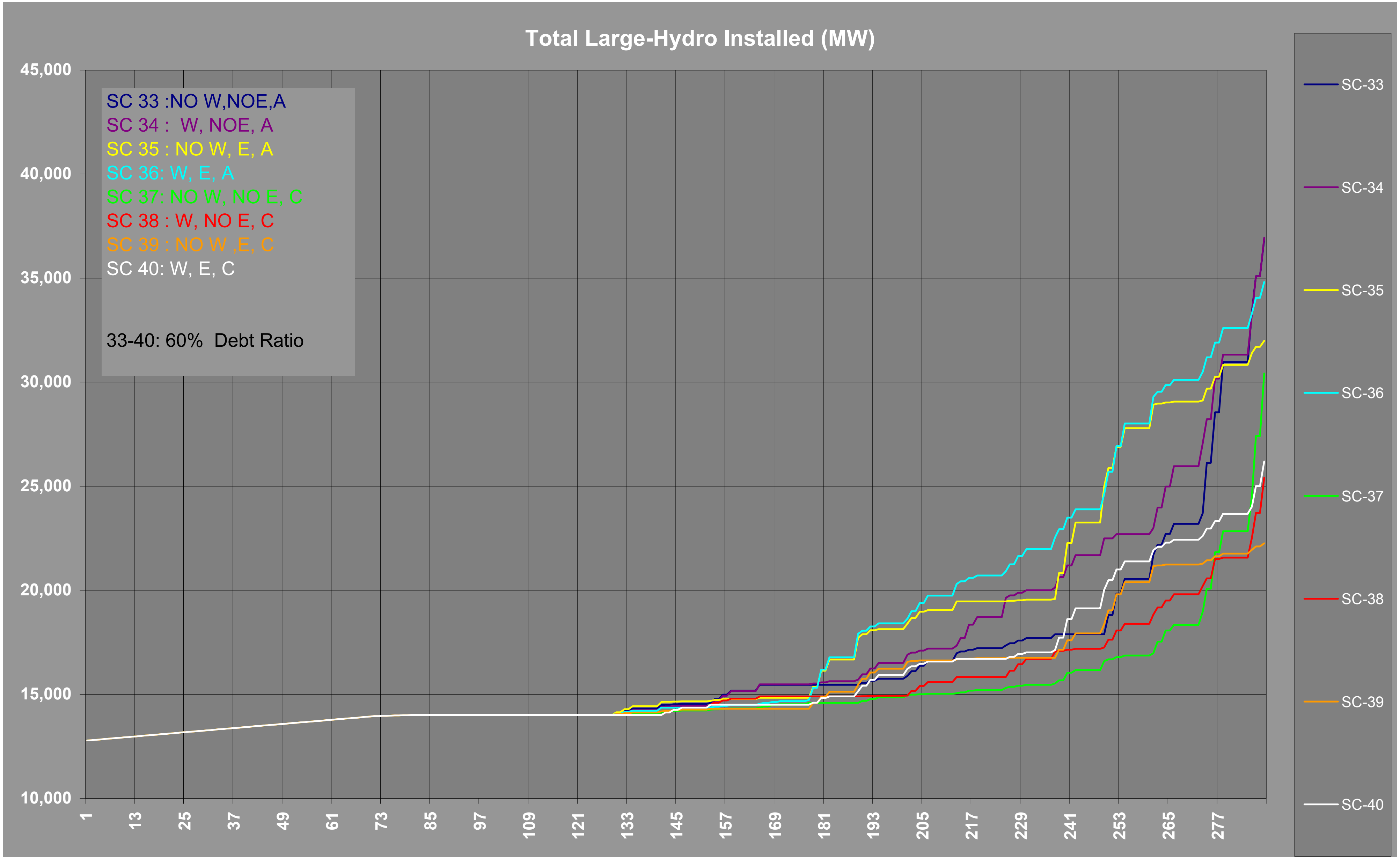
Total Large-Hydro Installed (MW)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

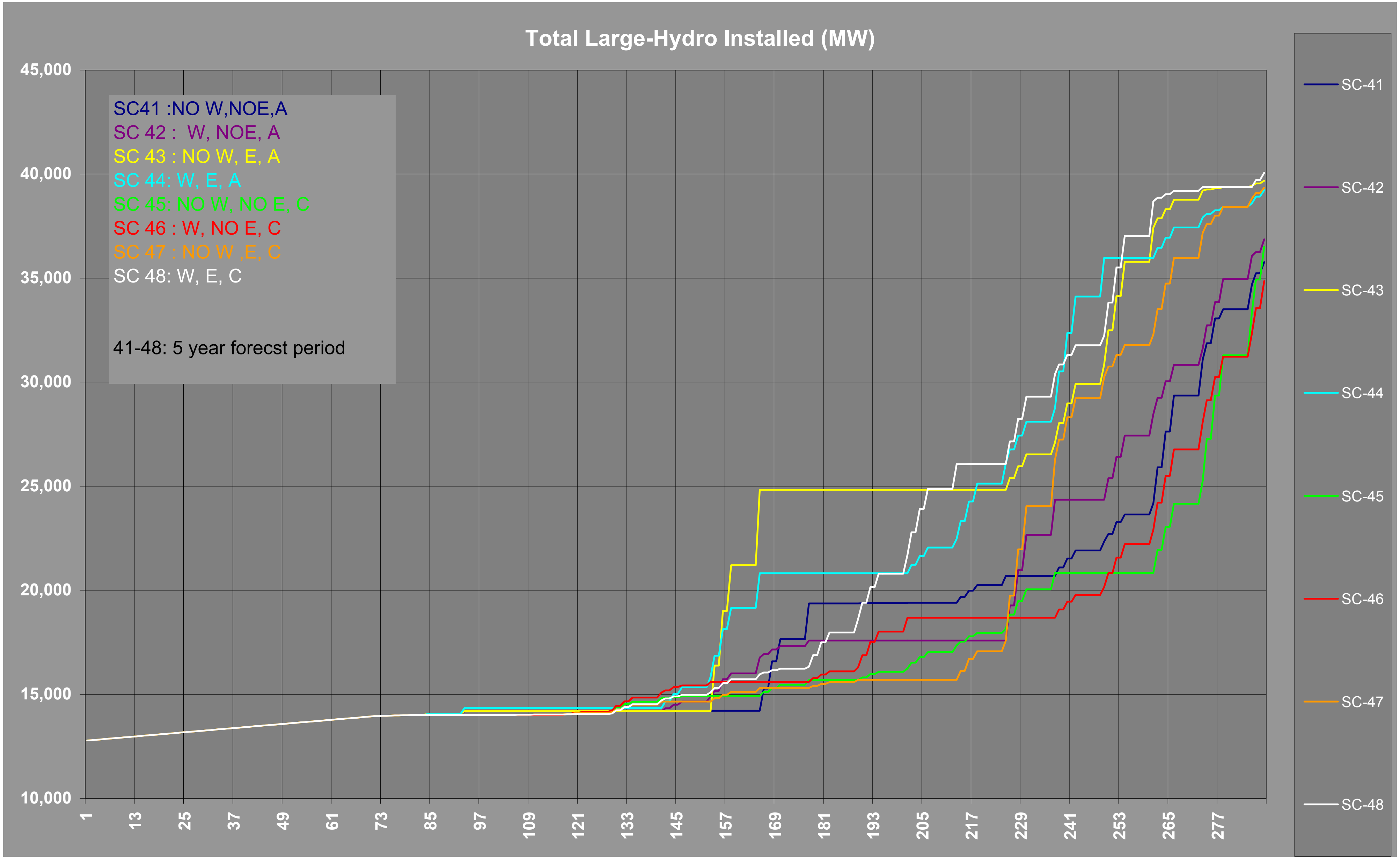

Total Large-Hydro Installed (MW)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16

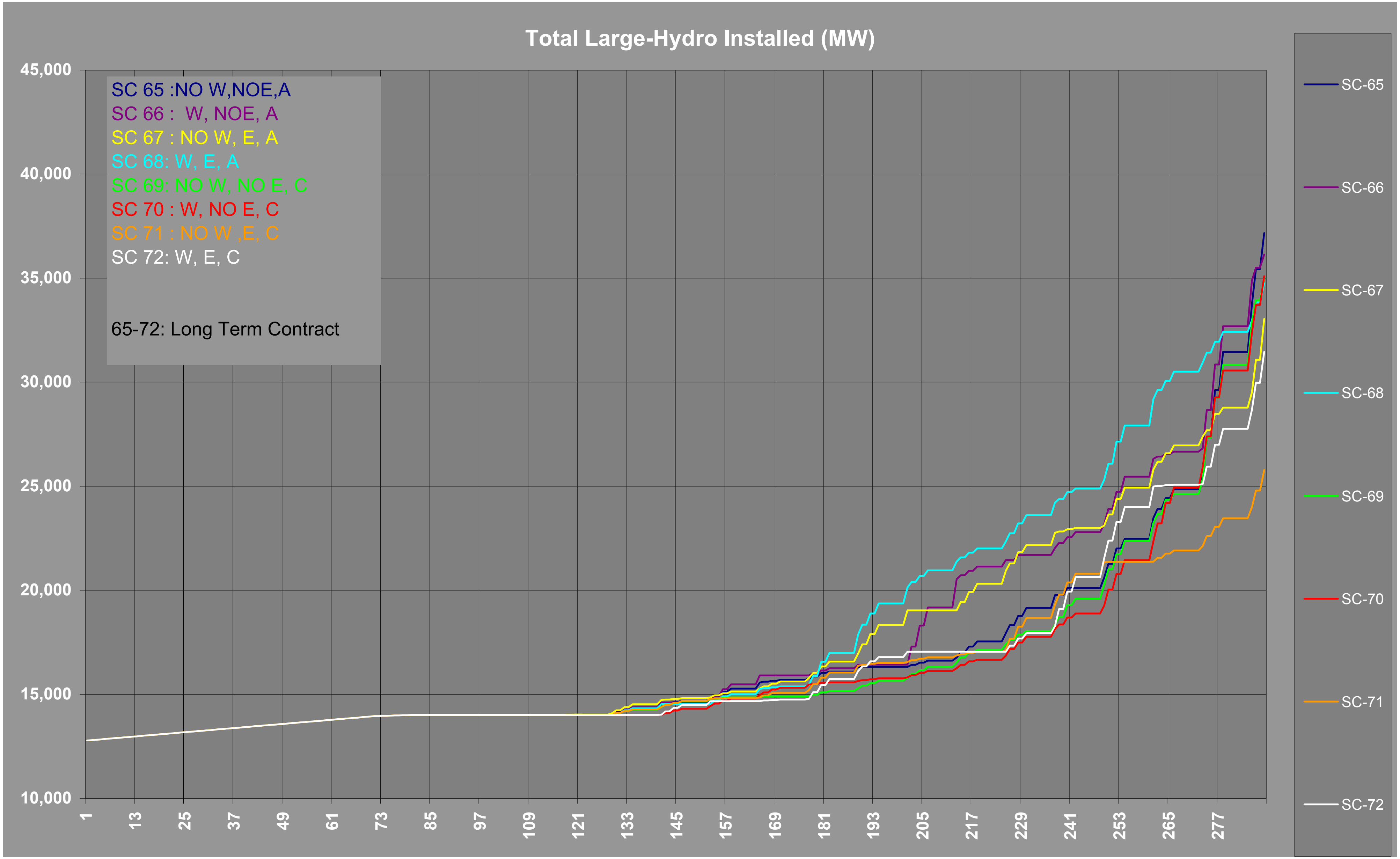


Total Large-Hydro Installed (MW)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24

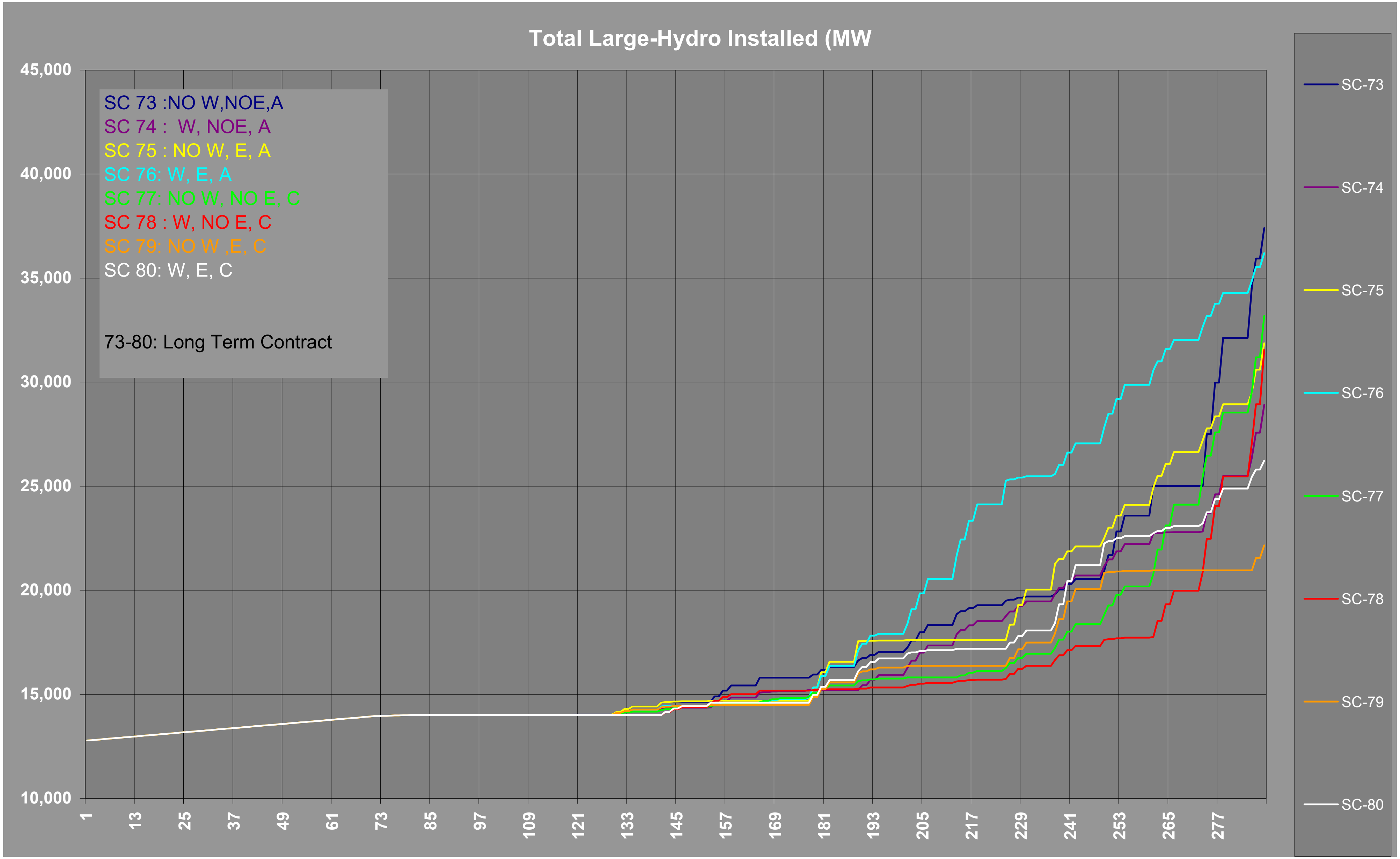

Total Large-Hydro Installed (MW)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32


Total Large-Hydro Installed (MW)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

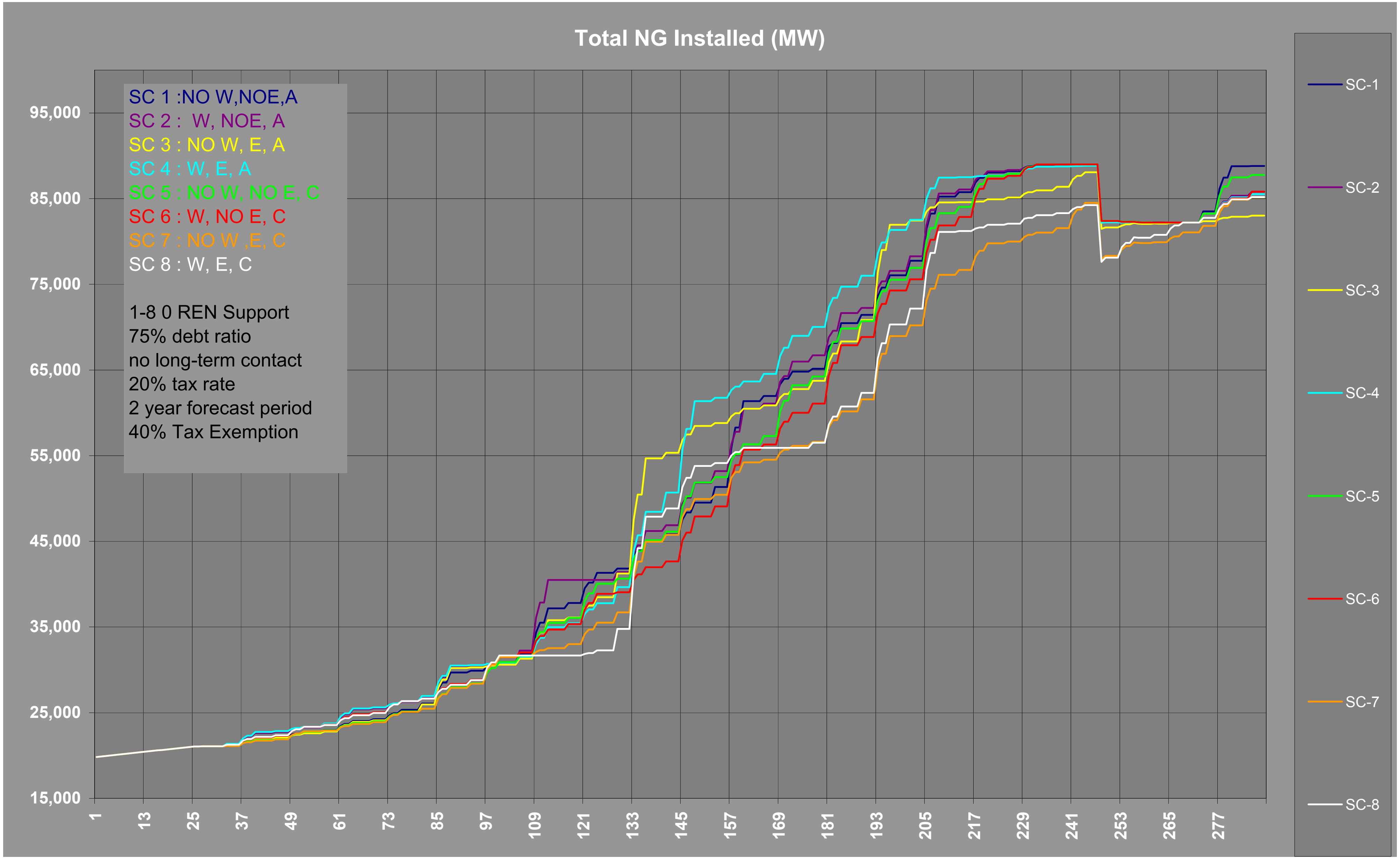

Total Large-Hydro Installed (MW)
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



Total Large-Hydro Installed (MW)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



Total Large-Hydro Installed (MW
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



Total NG Installed (MW)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
95,000
85,000
75,000
65,000
55,000
45,000
35,000
25,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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SC-1
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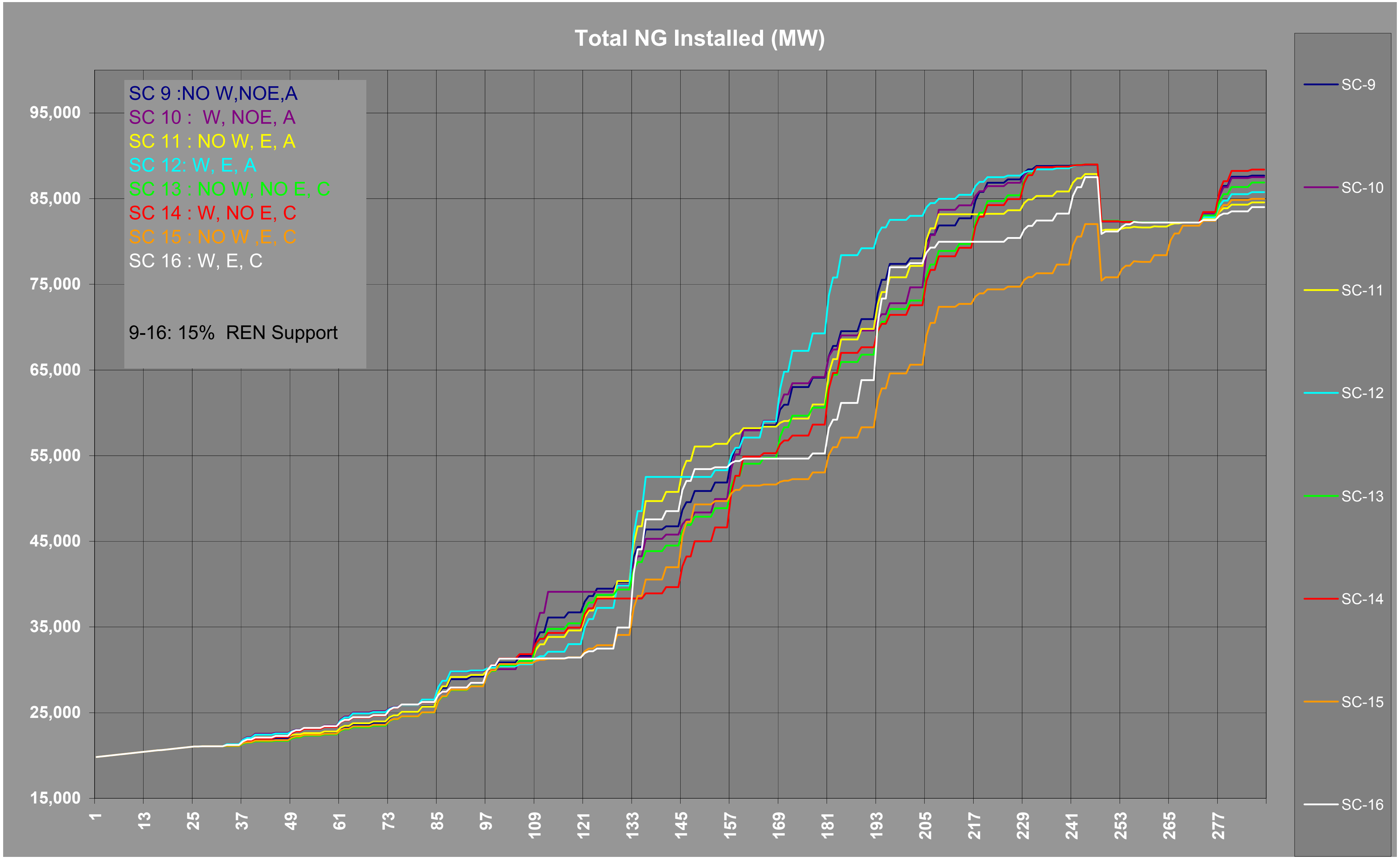
SC-6
SC-7
SC-8



Total NG Installed (MW)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
95,000
85,000
75,000
65,000
55,000
45,000
35,000
25,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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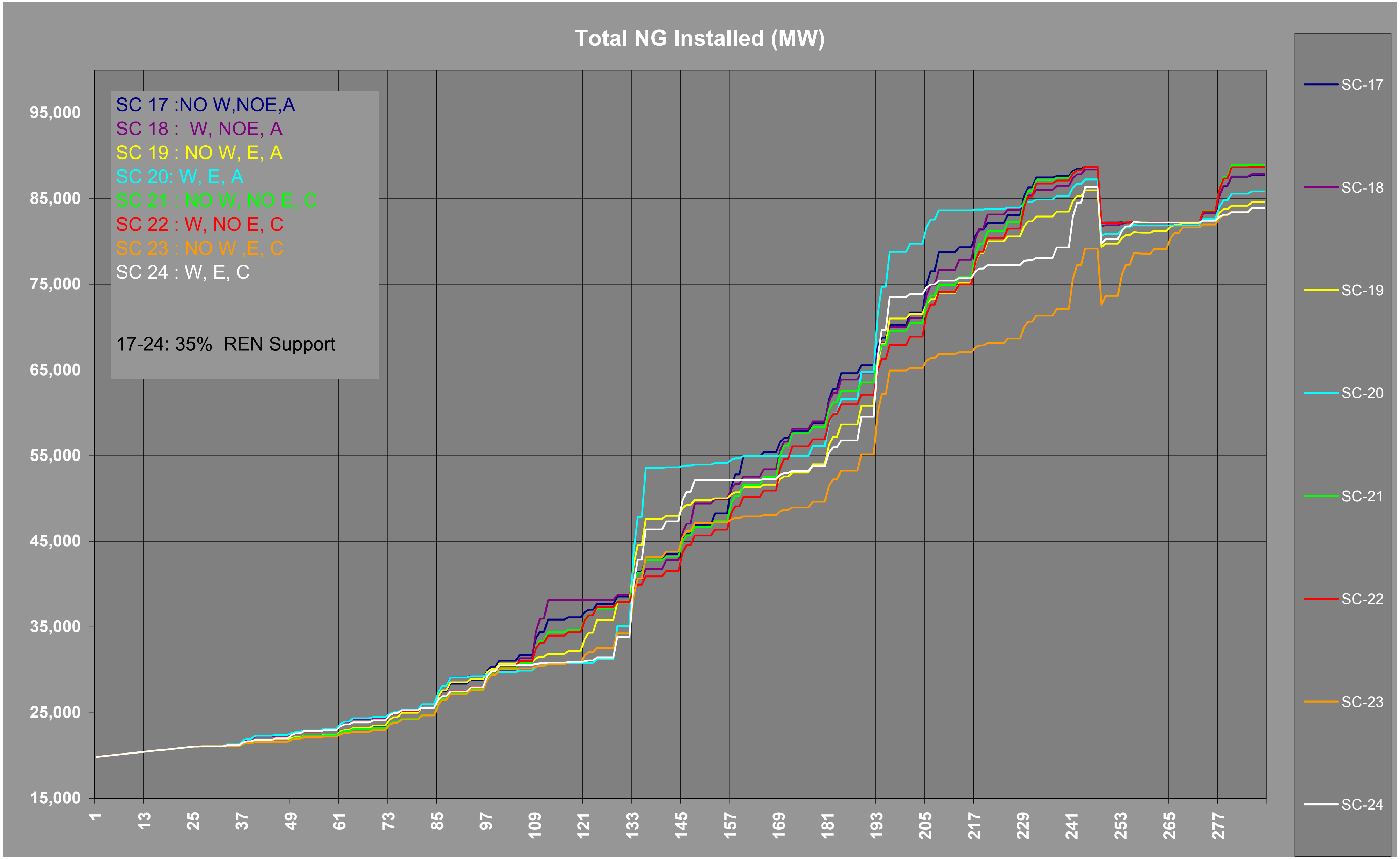
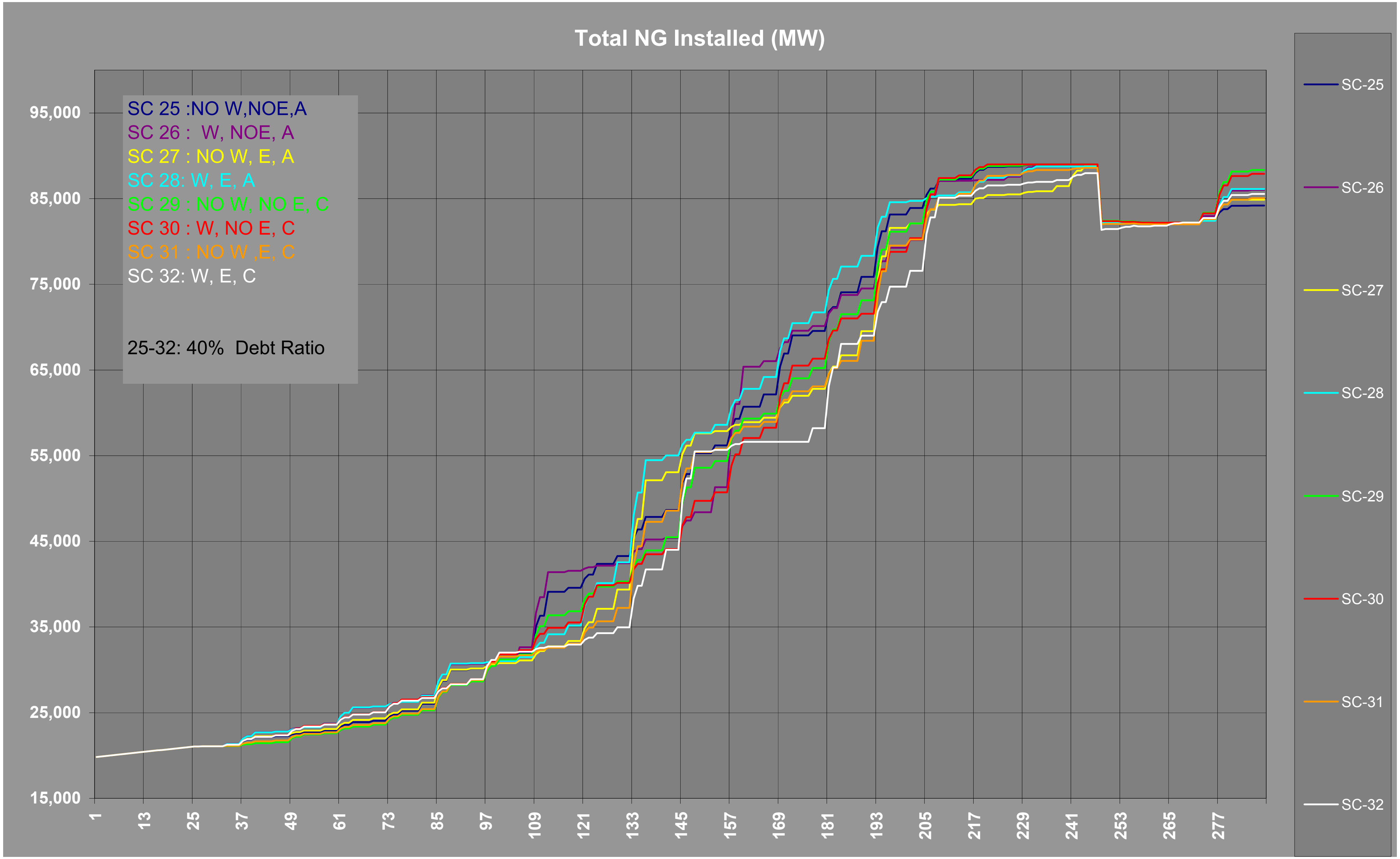
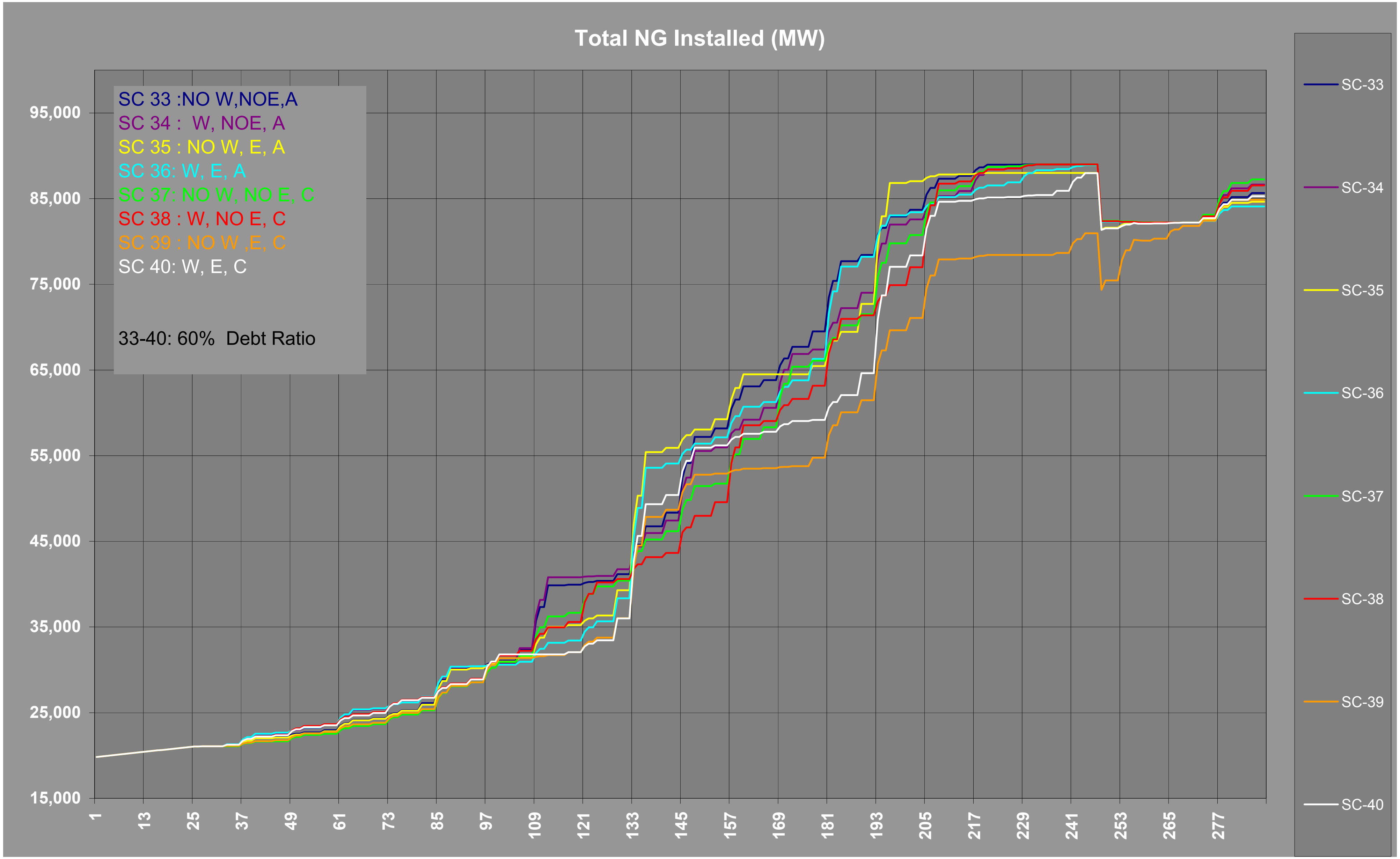
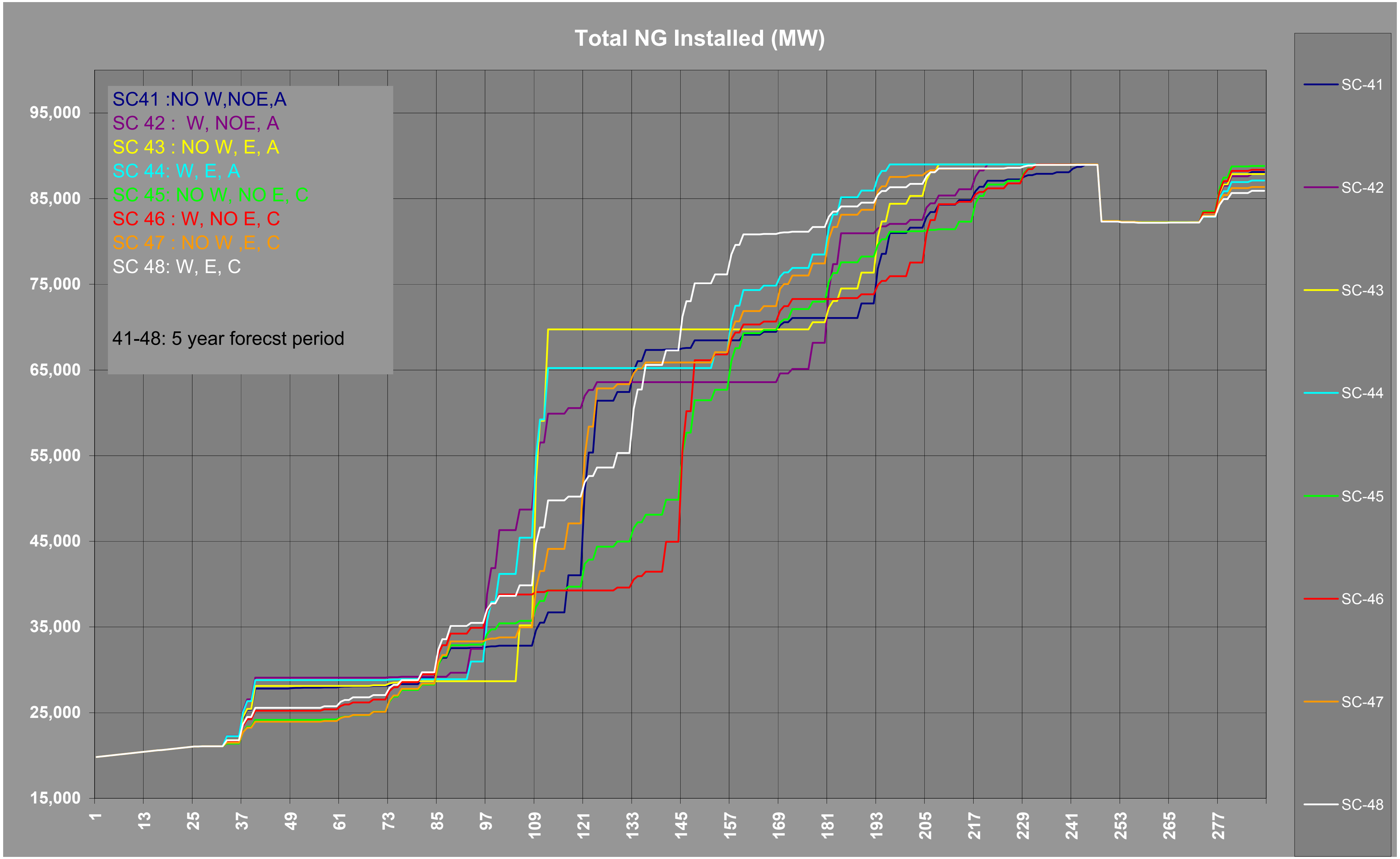
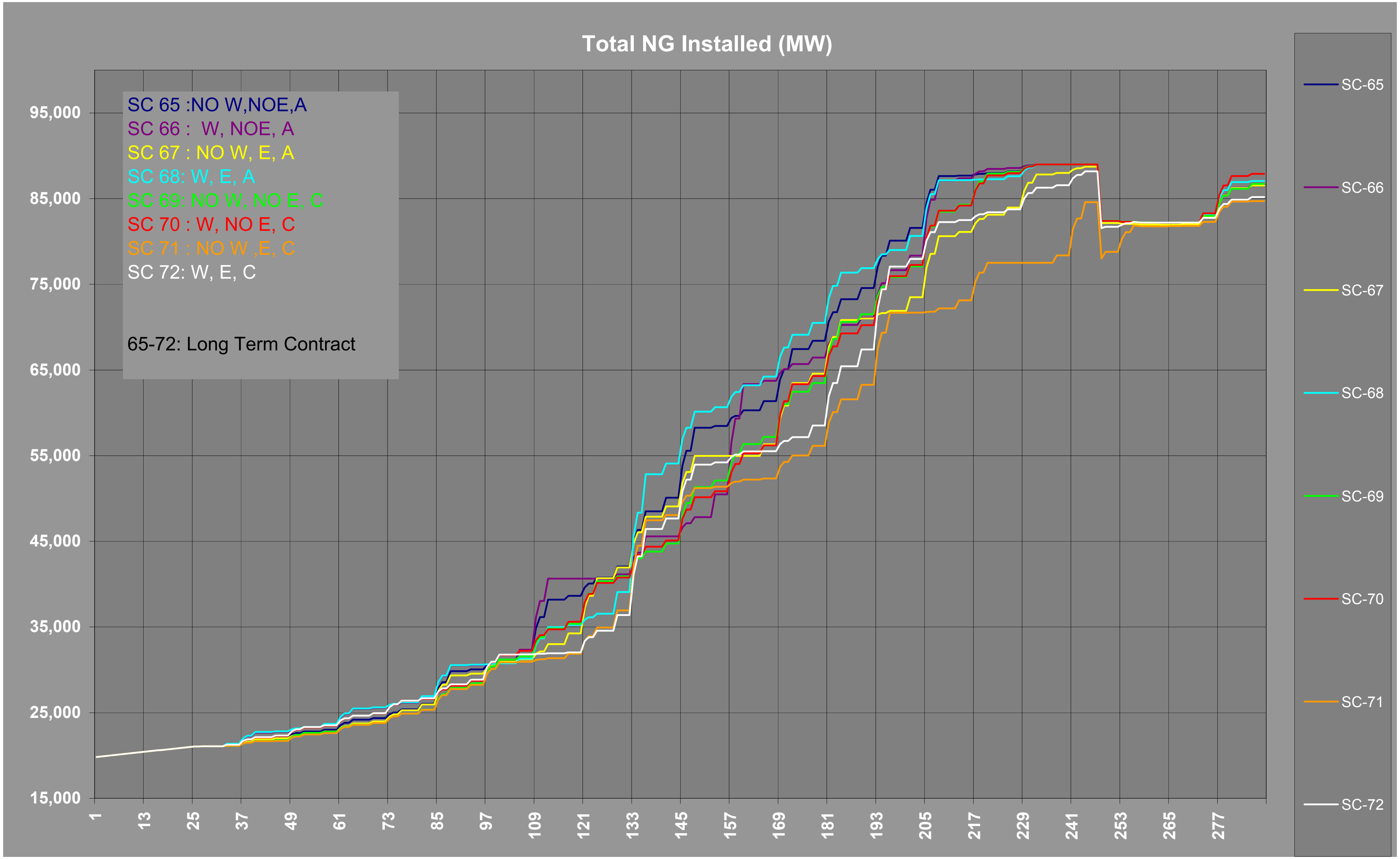
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16


Total NG Installed (MW)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
95,000
85,000
75,000
65,000
55,000
45,000
35,000
25,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24

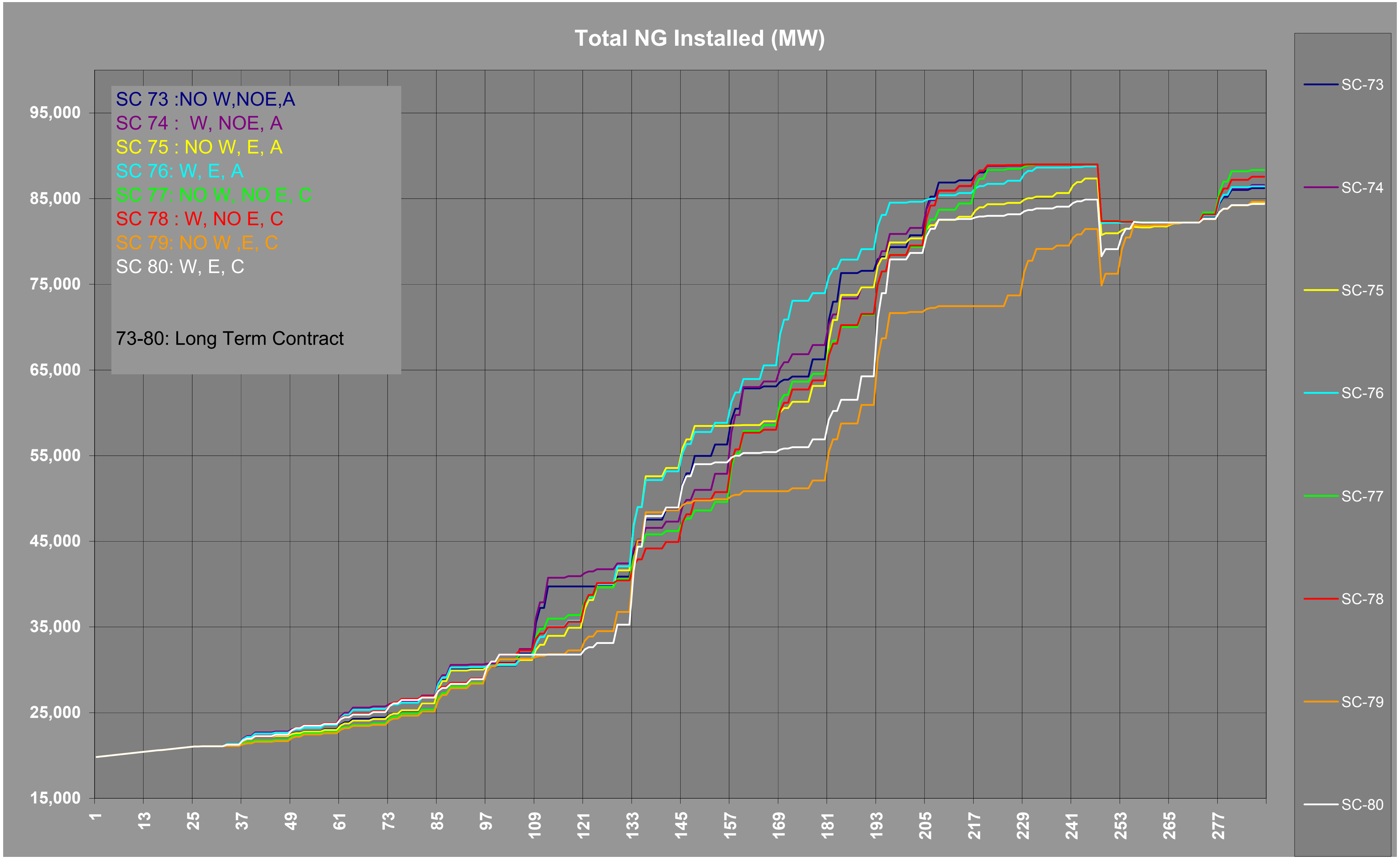

Total NG Installed (MW)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
95,000
85,000
75,000
65,000
55,000
45,000
35,000
25,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32


Total NG Installed (MW)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
95,000
85,000
75,000
65,000
55,000
45,000
35,000
25,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

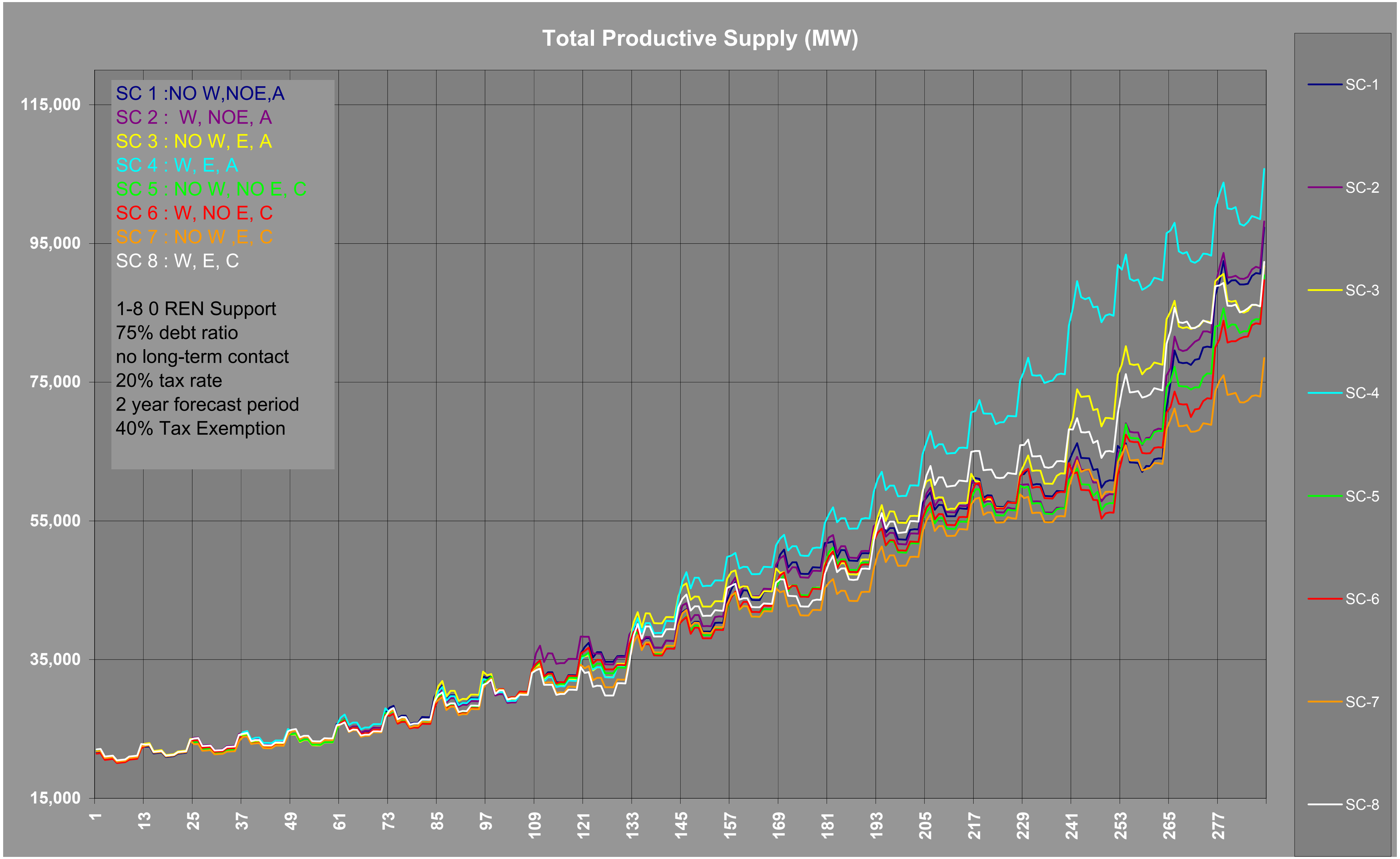

Total NG Installed (MW)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
95,000
85,000
75,000
65,000
55,000
45,000
35,000
25,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48

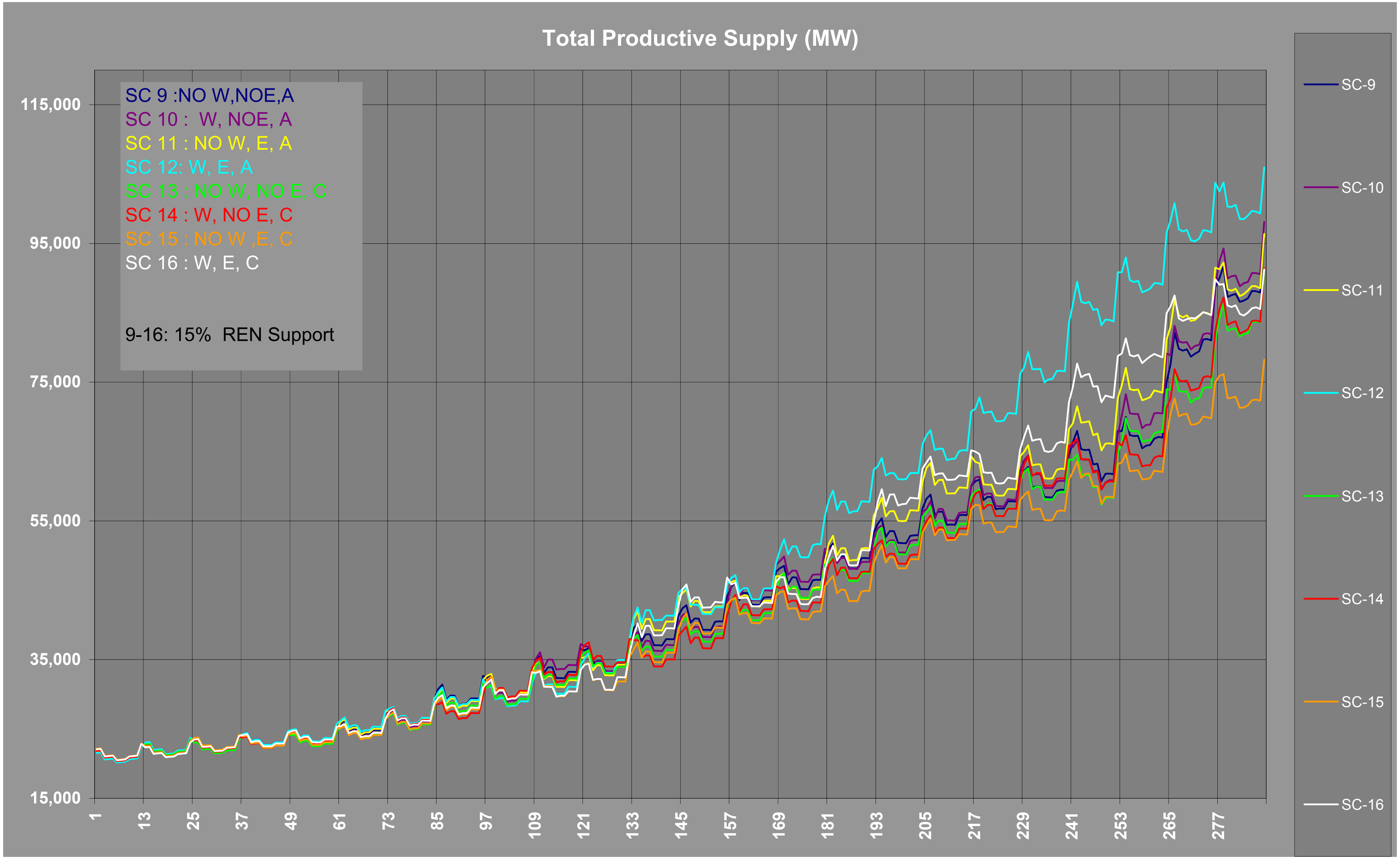


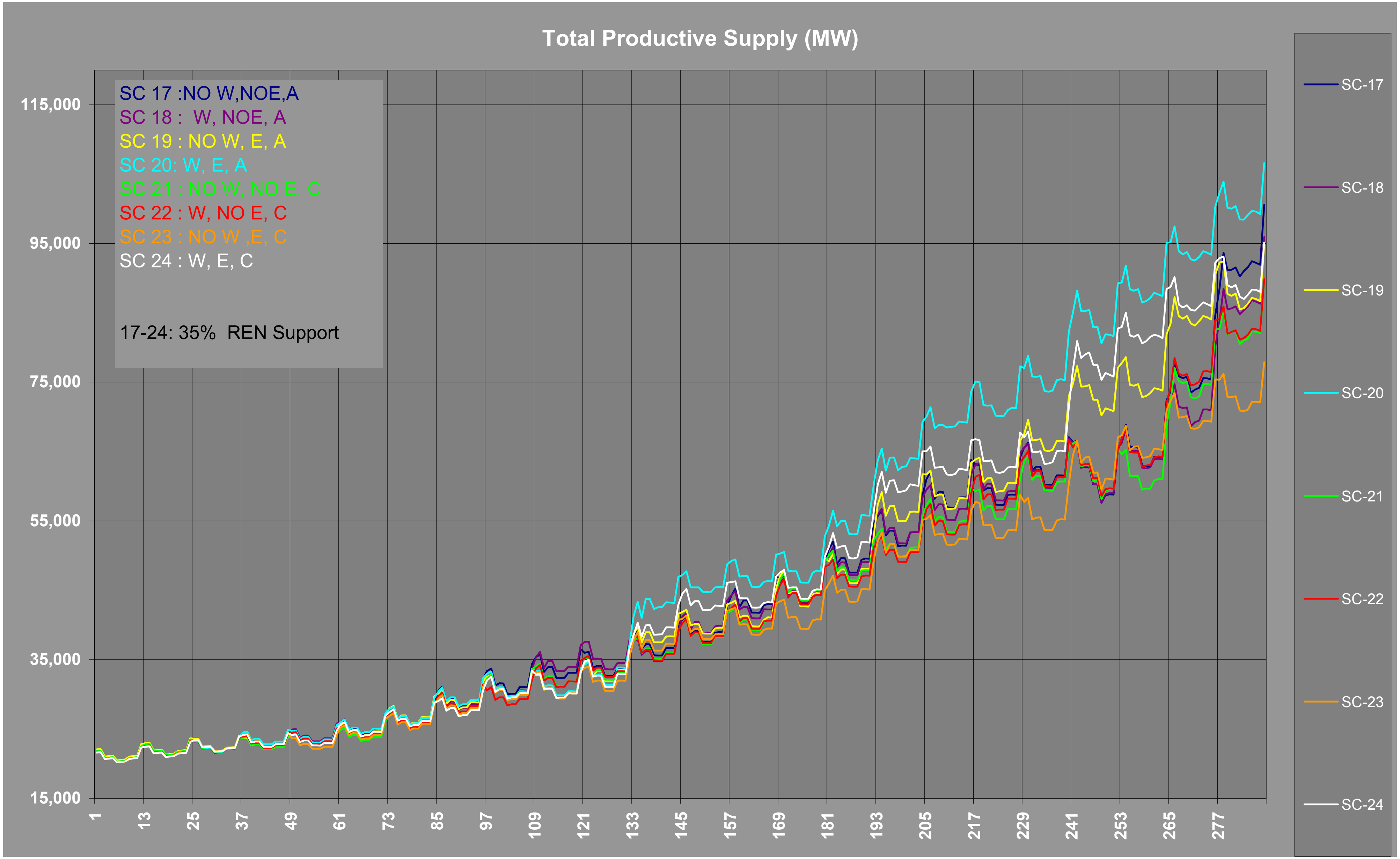
Total NG Installed (MW)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
95,000
85,000
75,000
65,000
55,000
45,000
35,000
25,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



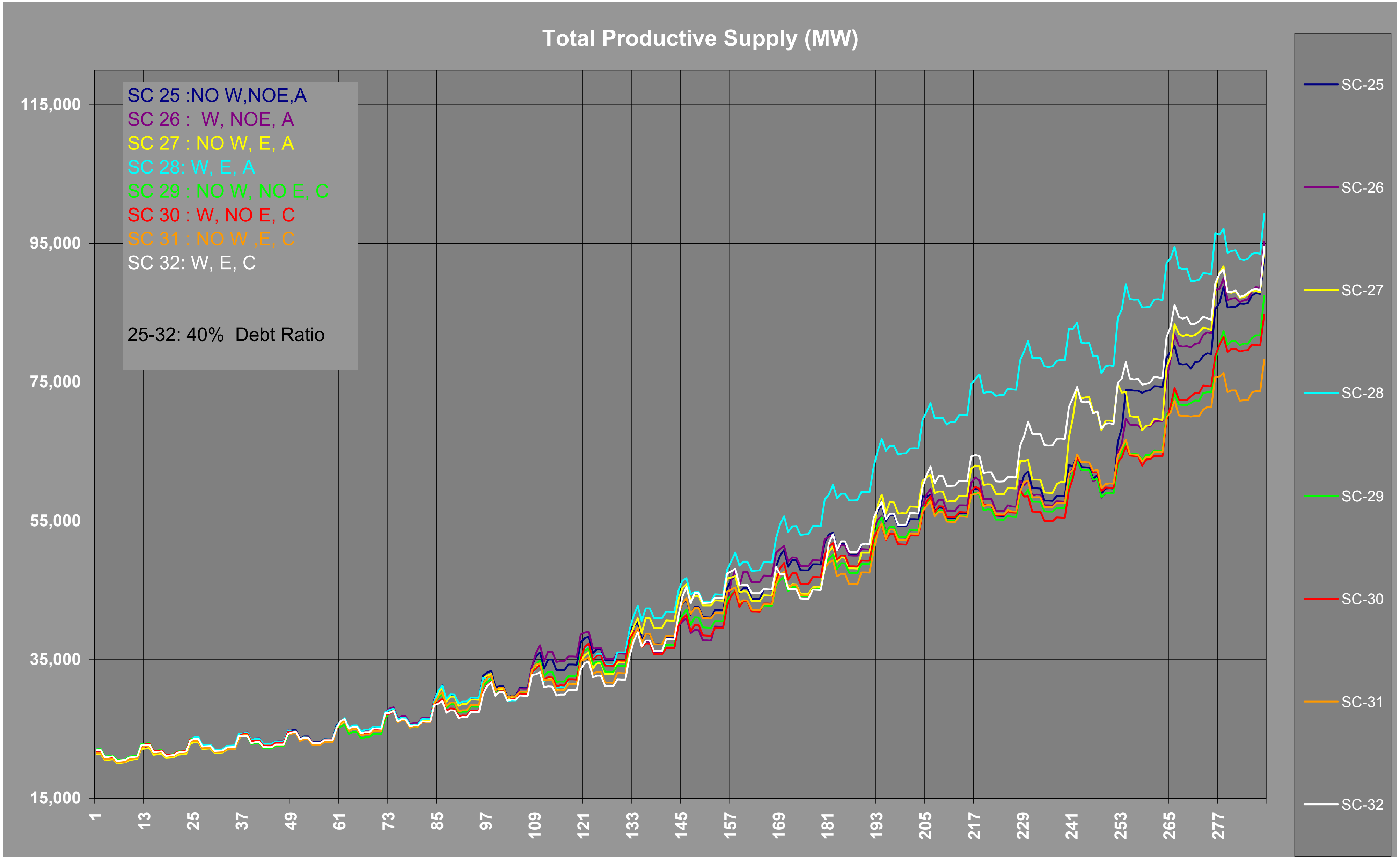
Total NG Installed (MW)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
95,000
85,000
75,000
65,000
55,000
45,000
35,000
25,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

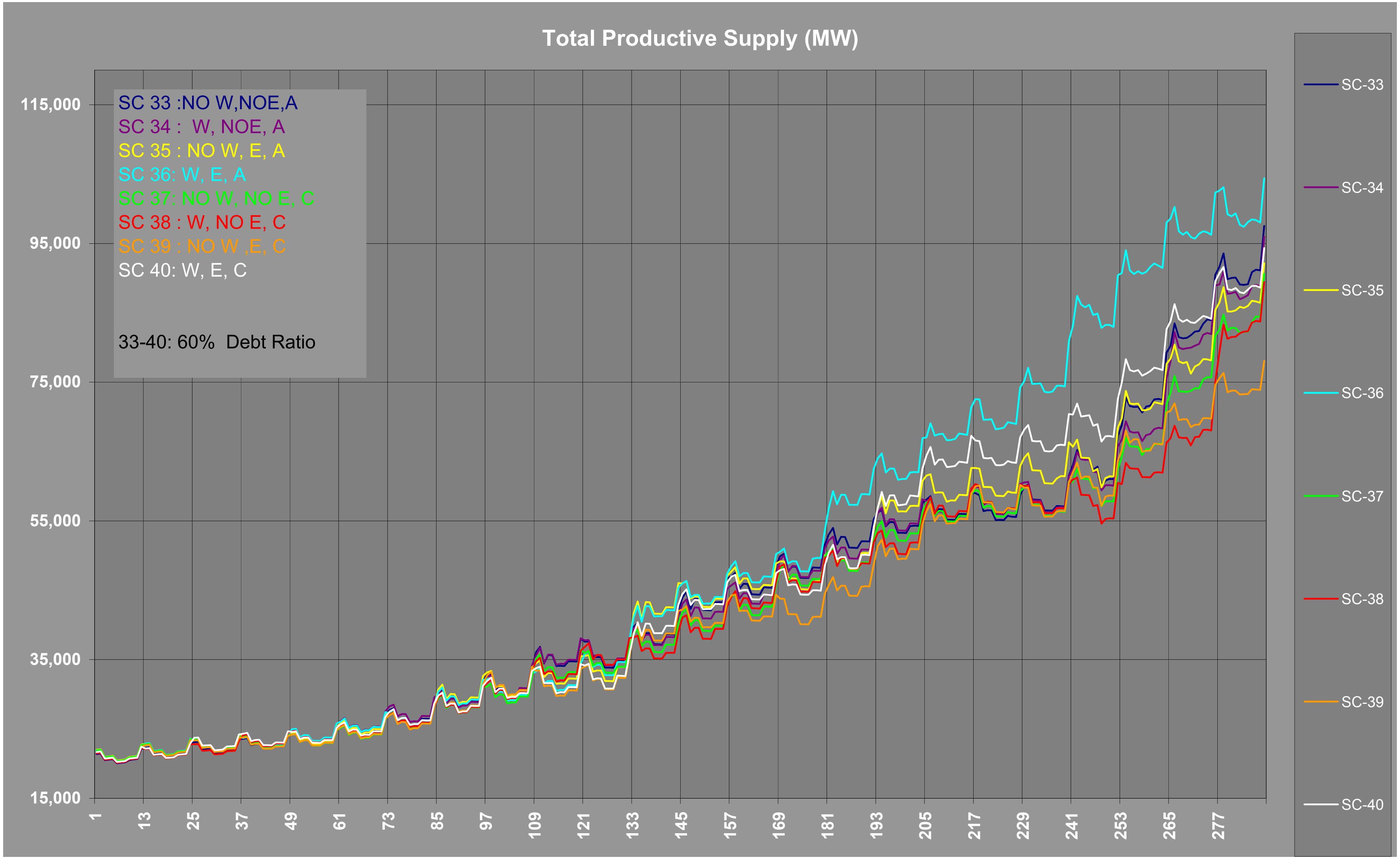

Total Productive Supply (MW)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

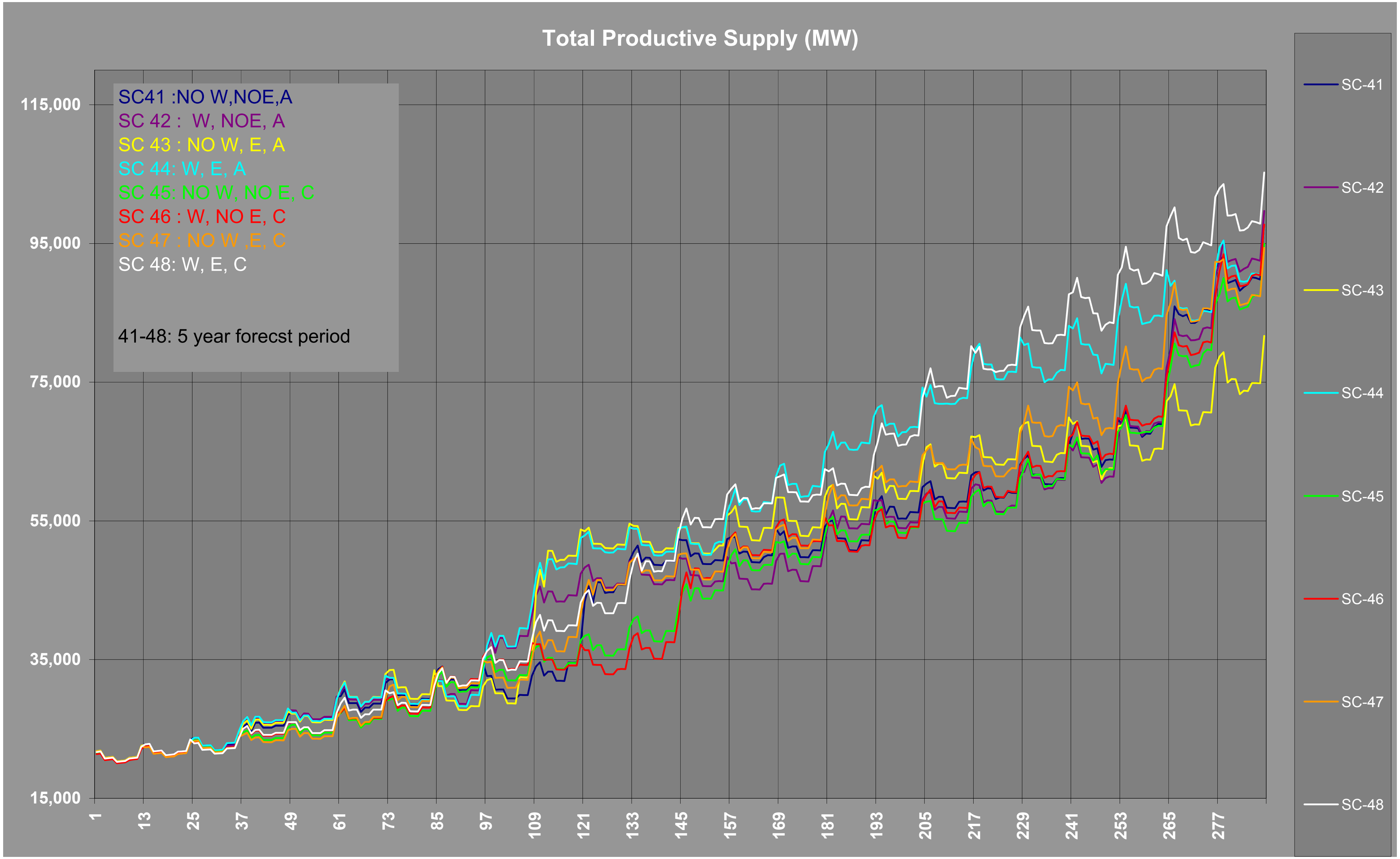

Total Productive Supply (MW)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



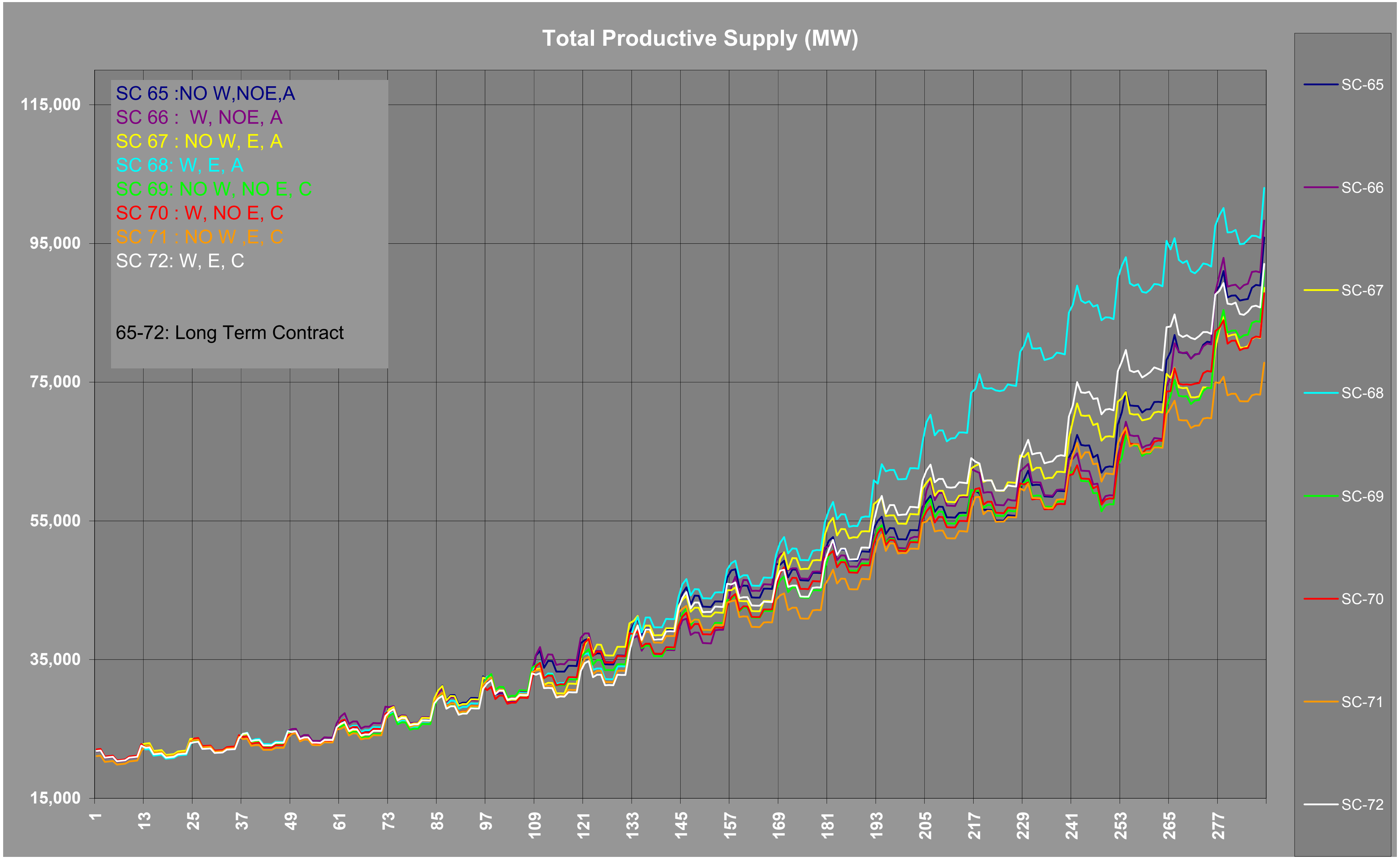
Total Productive Supply (MW)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24


Total Productive Supply (MW)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32

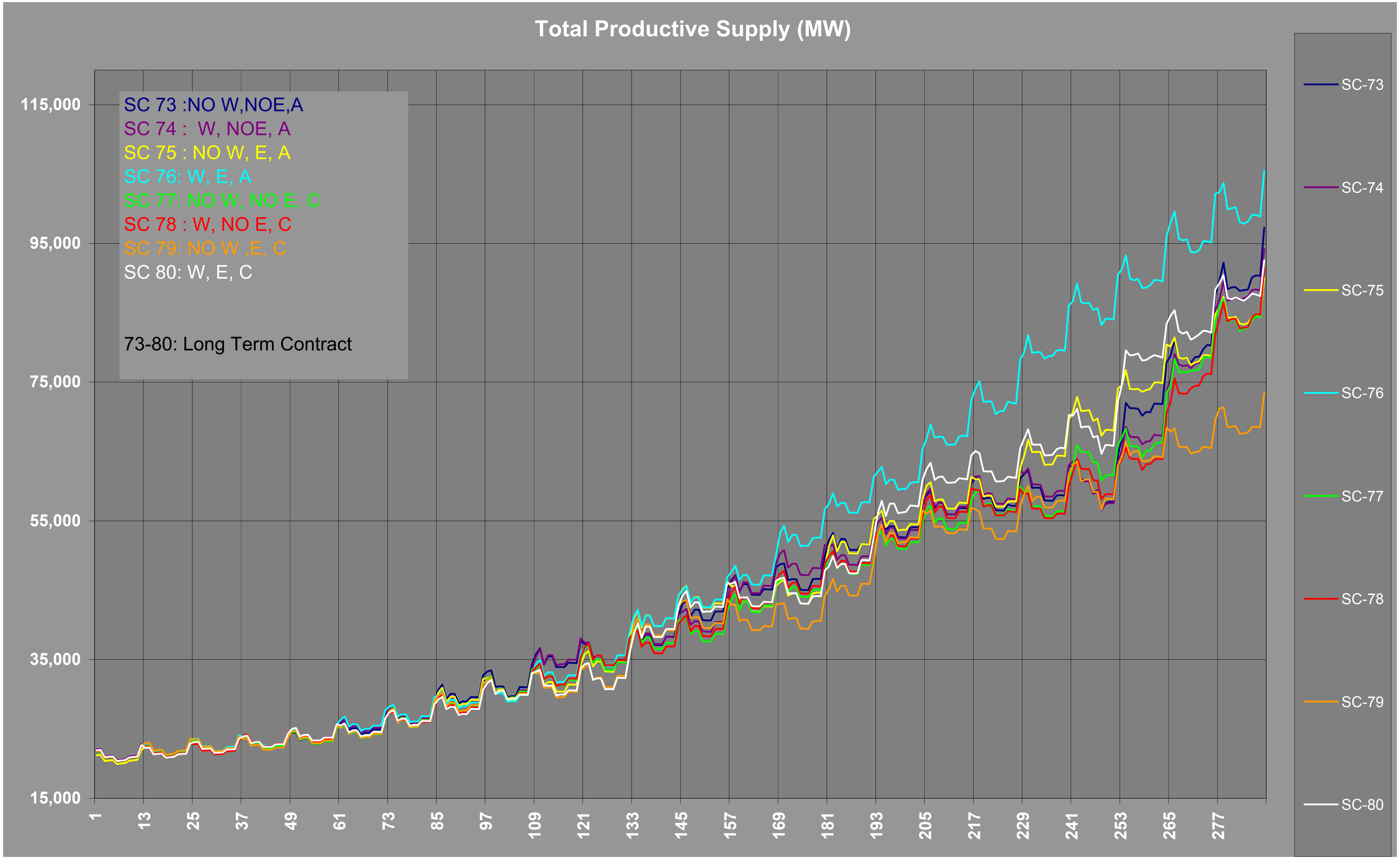

Total Productive Supply (MW)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



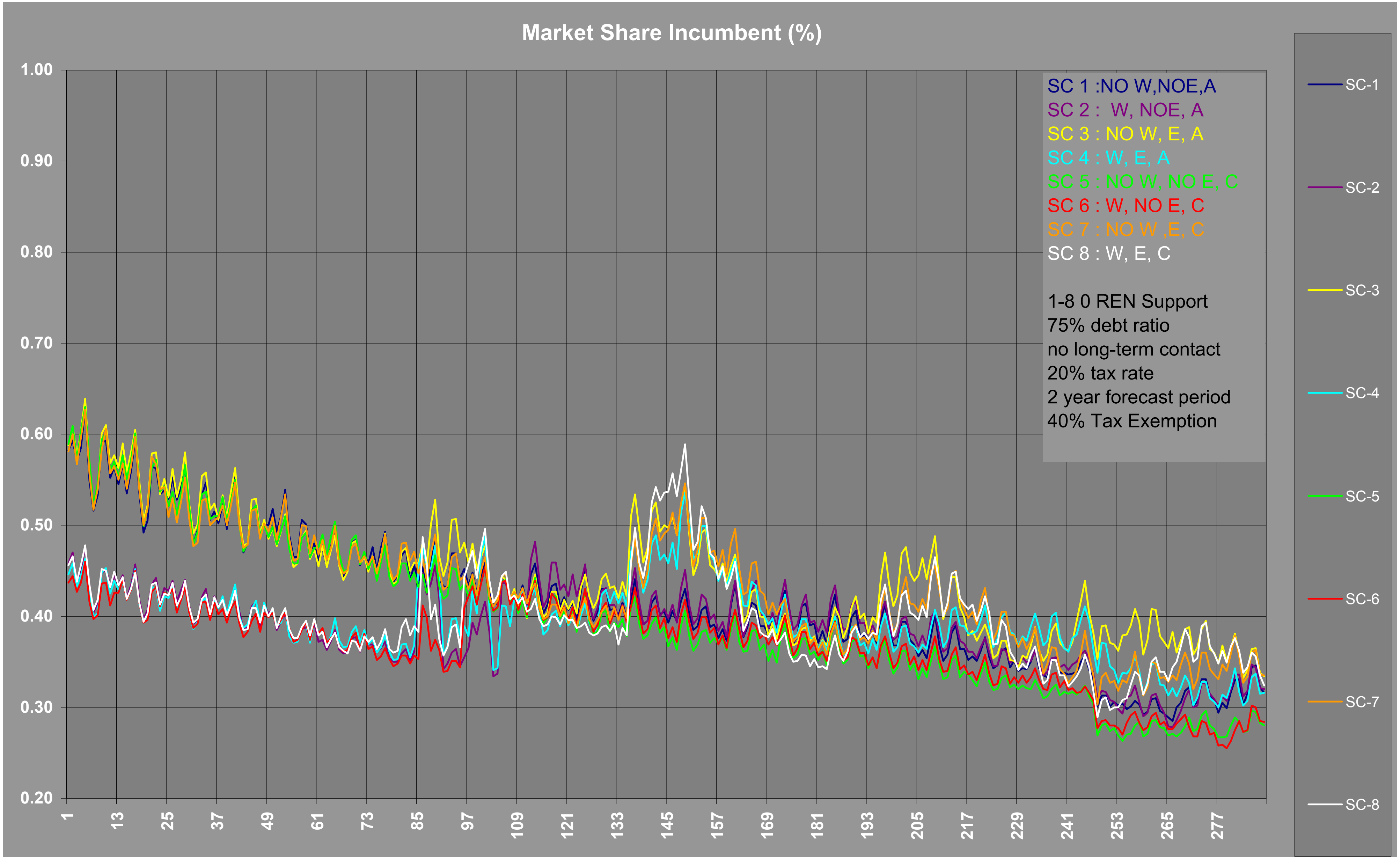
Total Productive Supply (MW)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48

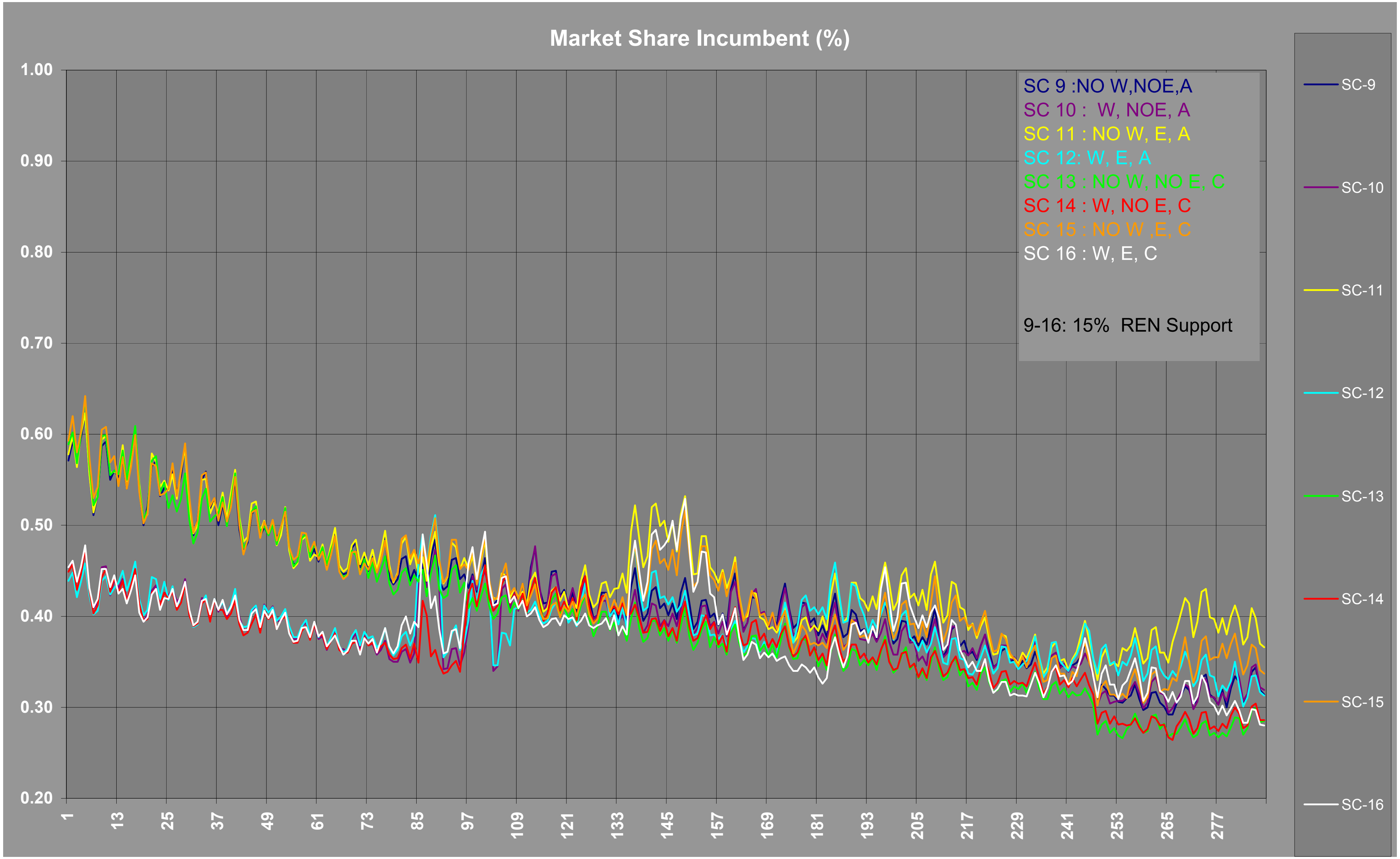


Total Productive Supply (MW)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

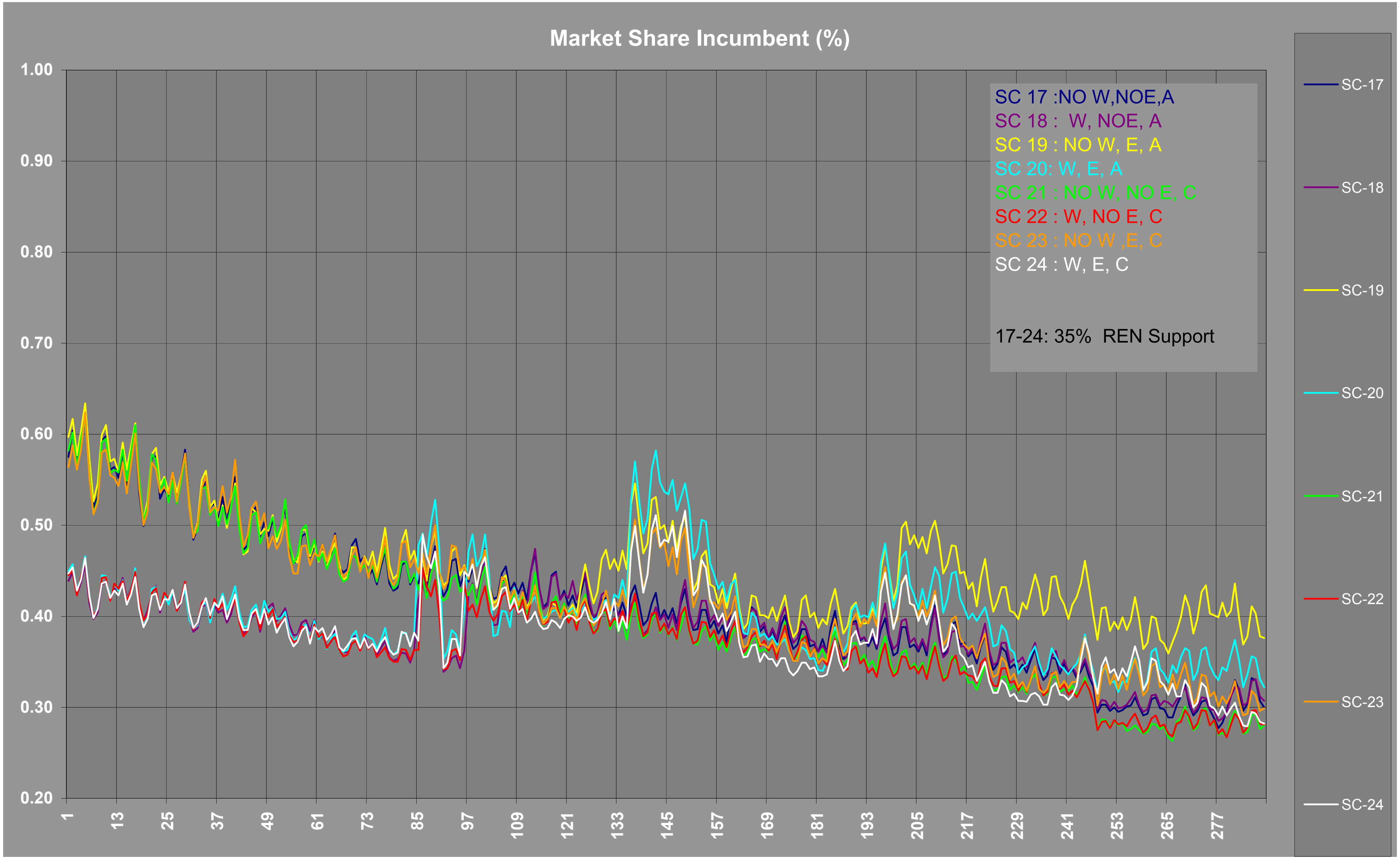


Total Productive Supply (MW)
115,000
95,000
75,000
55,000
35,000
15,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

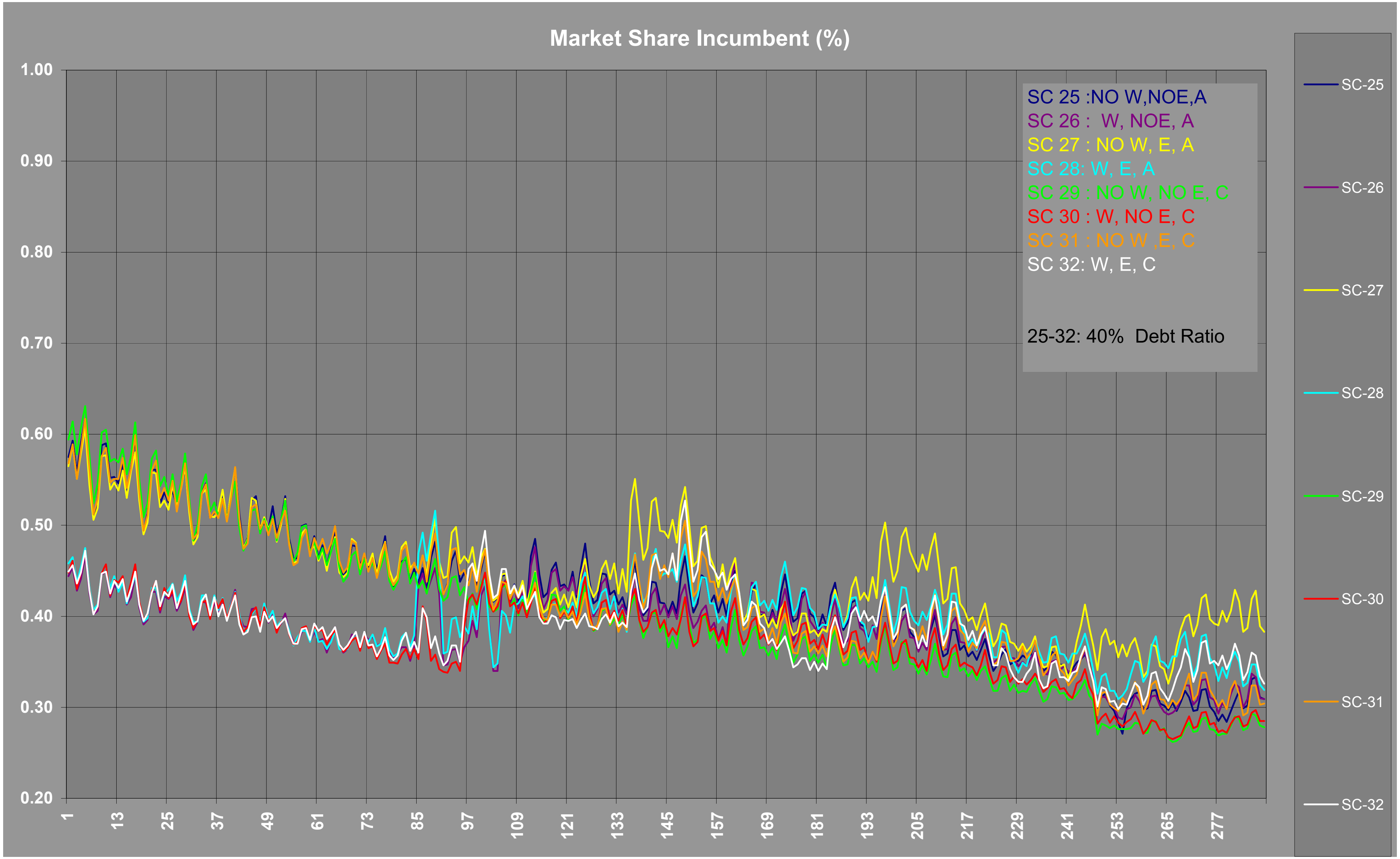

Market Share Incumbent (%)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



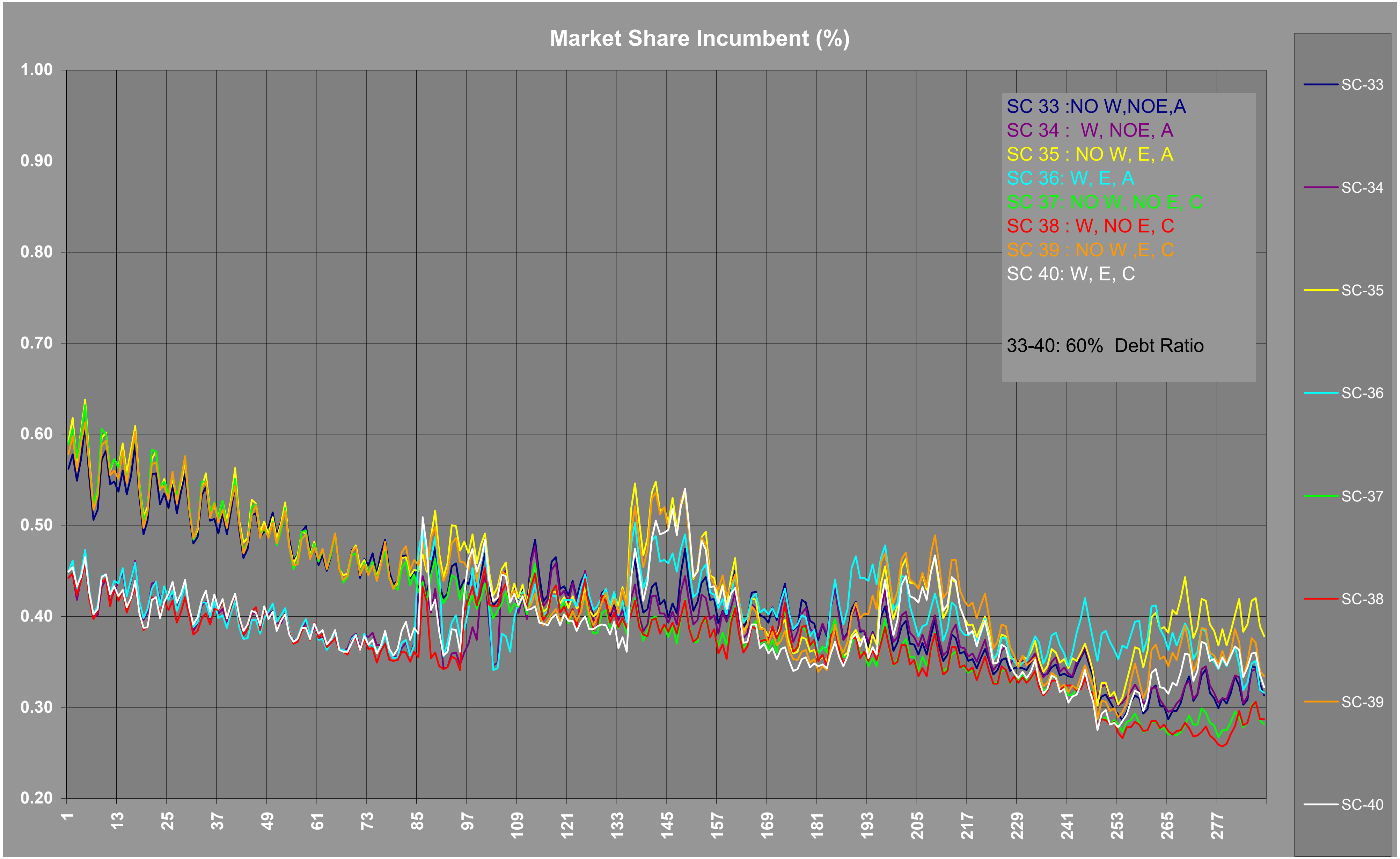
Market Share Incumbent (%)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



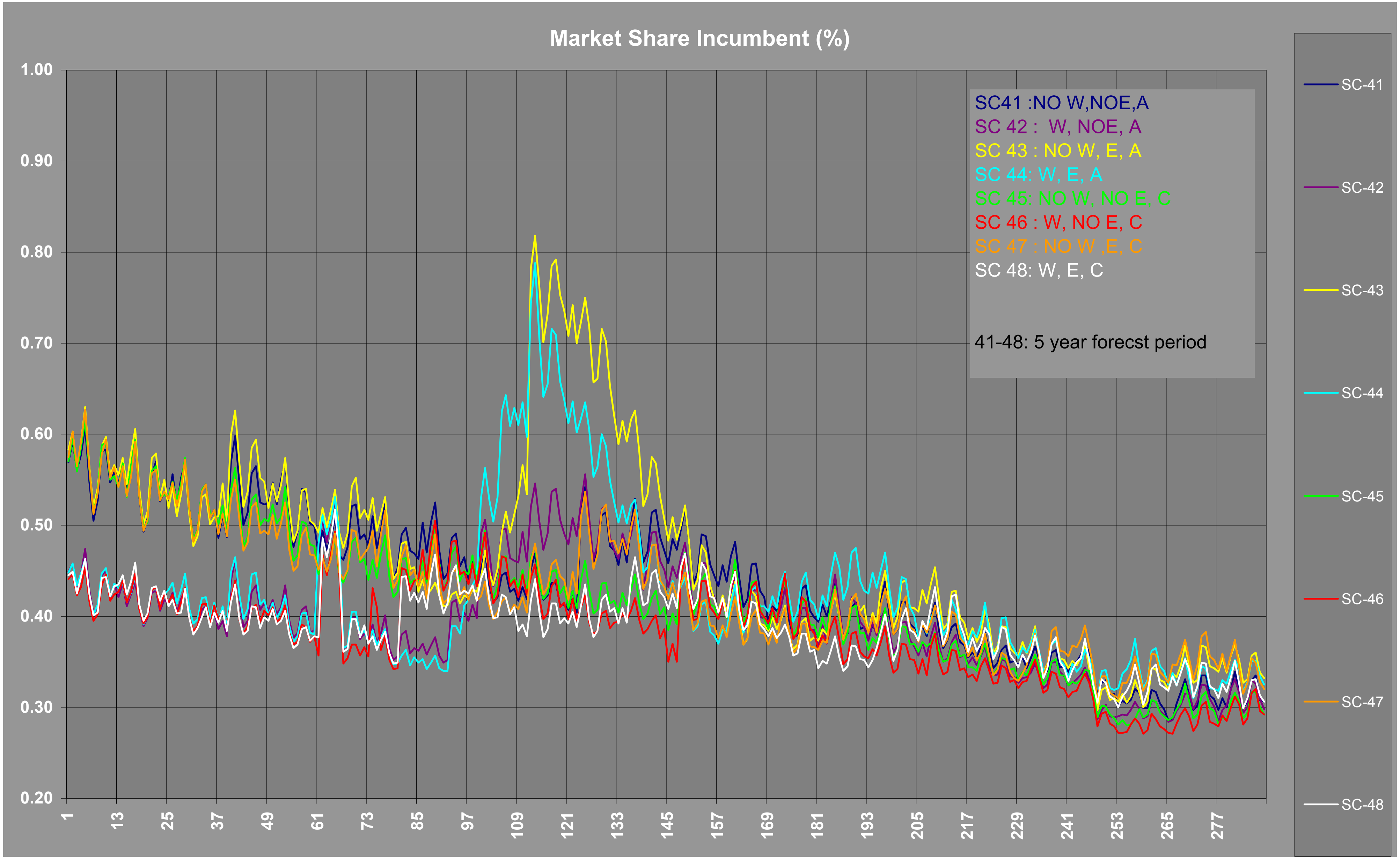
Market Share Incumbent (%)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24



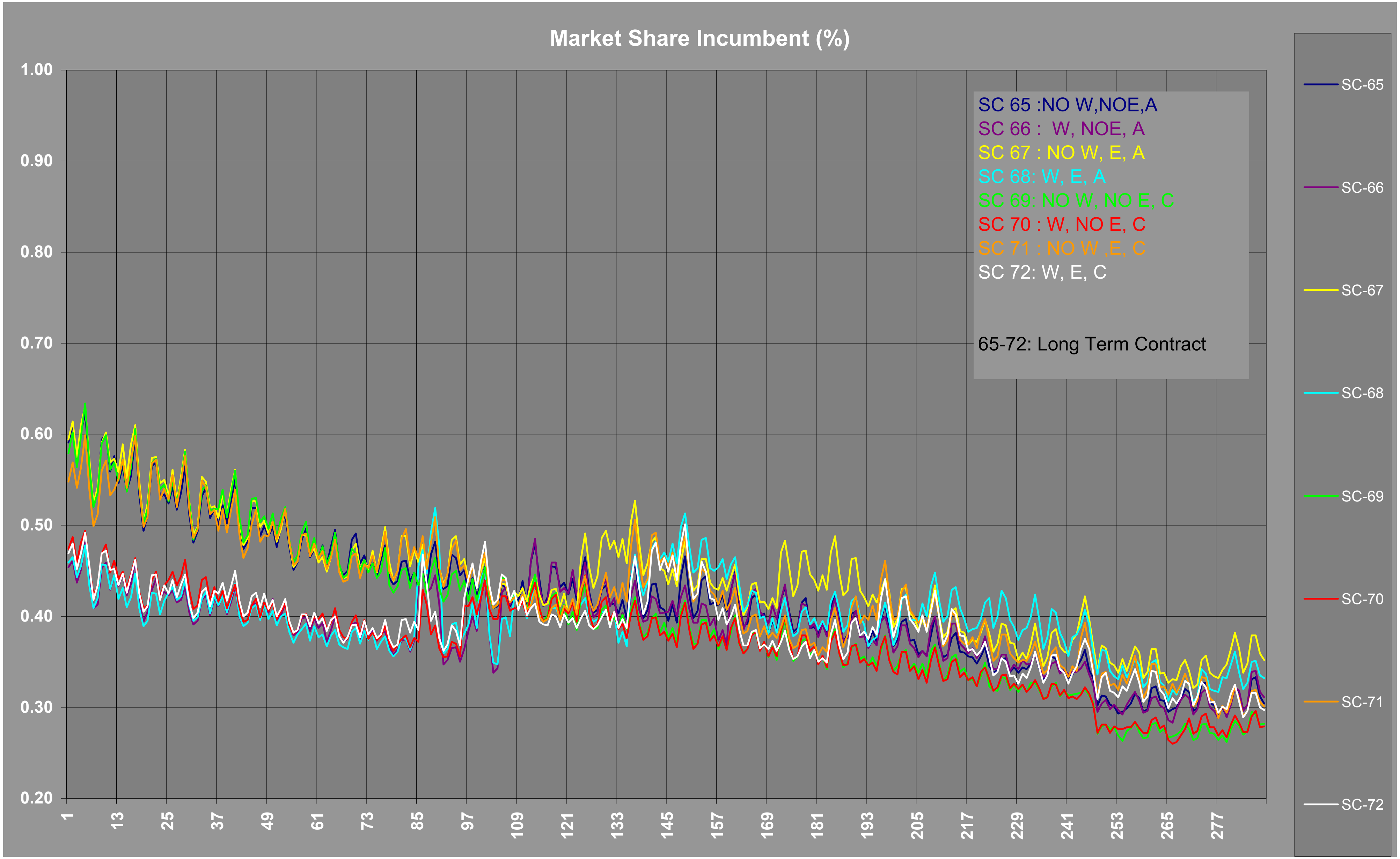
Market Share Incumbent (%)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32

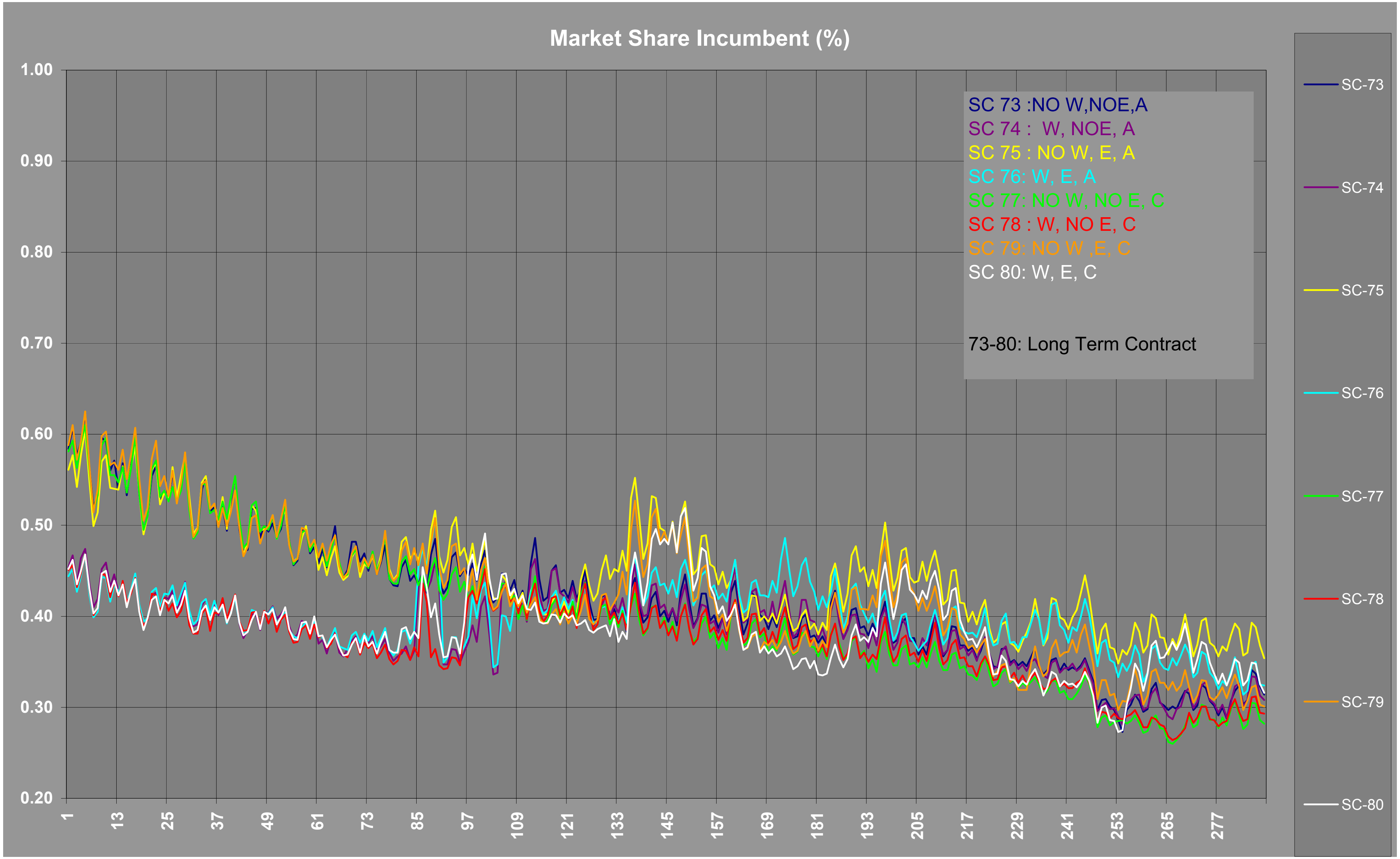


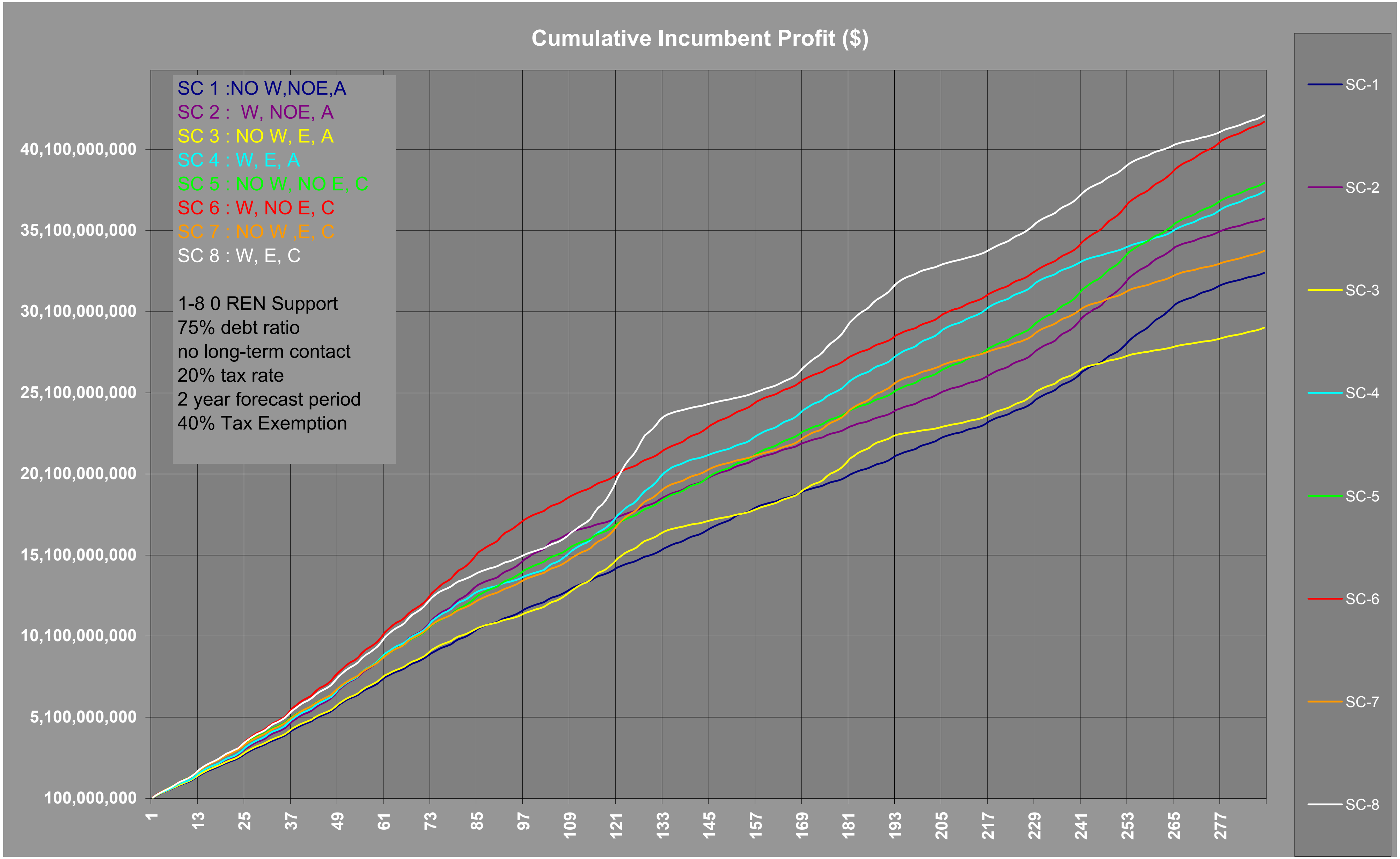
Market Share Incumbent (%)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



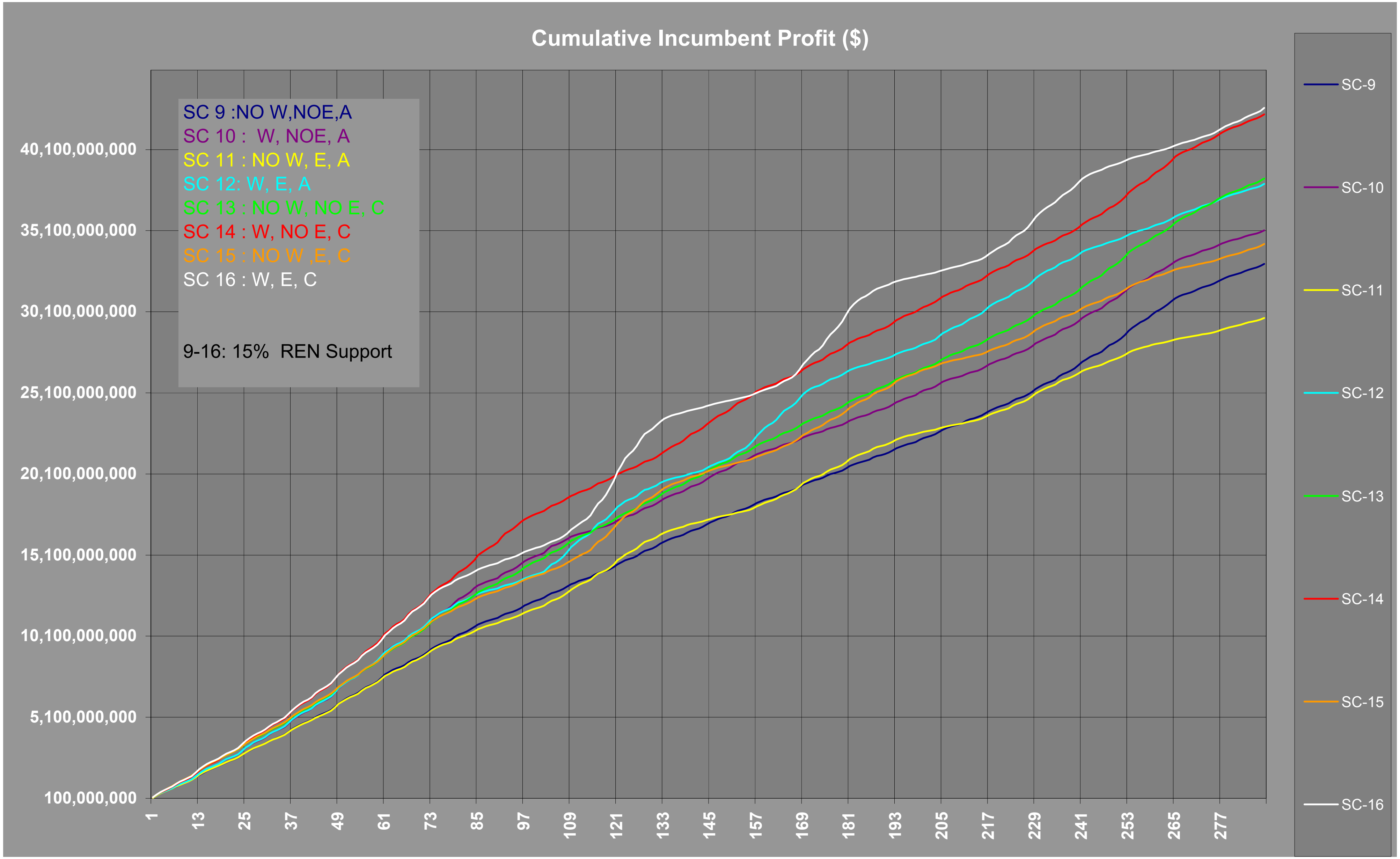
Market Share Incumbent (%)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48


Market Share Incumbent (%)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

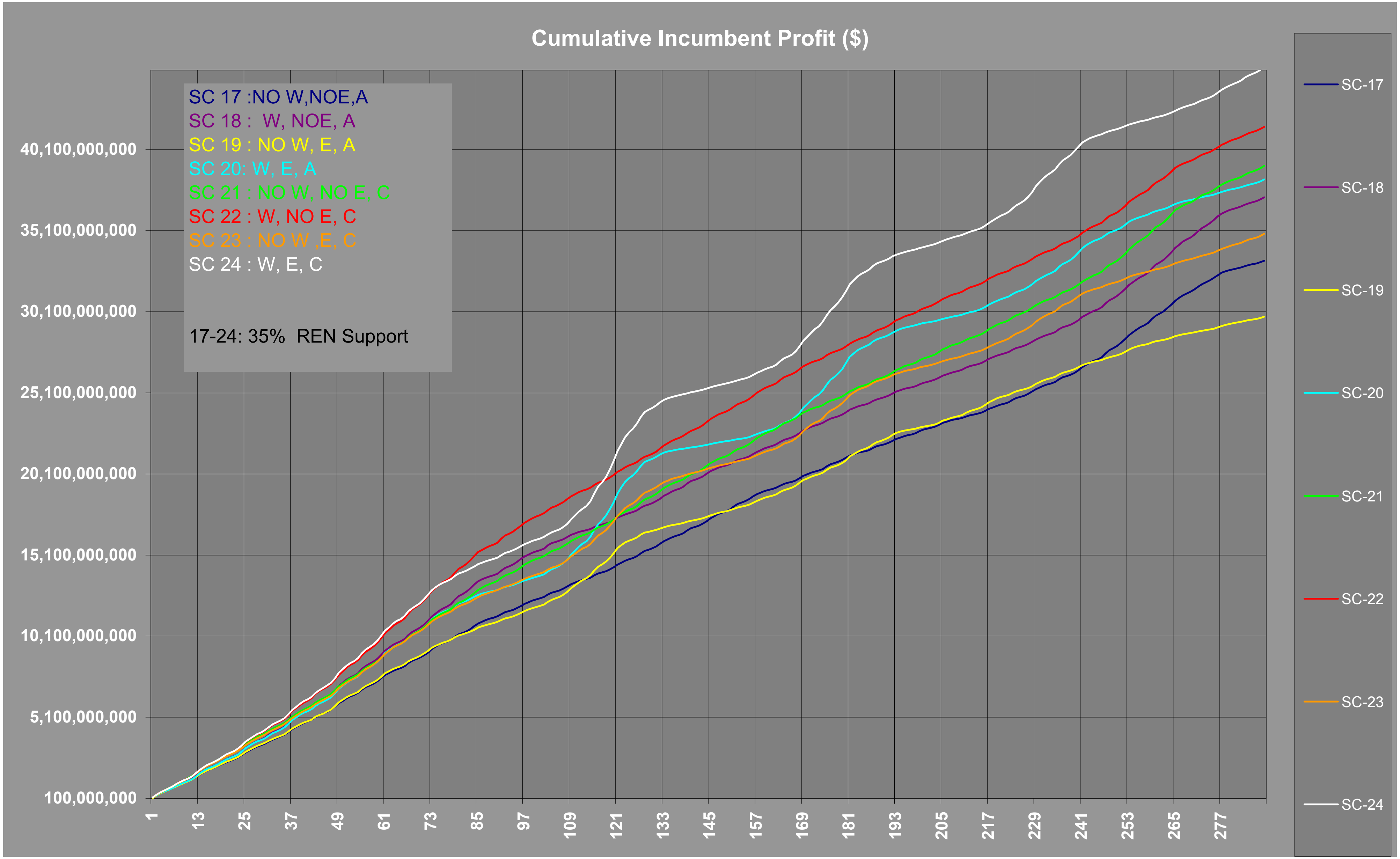

Market Share Incumbent (%)
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



Cumulative Incumbent Profit ($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Cumulative Incumbent Profit ($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



Cumulative Incumbent Profit ($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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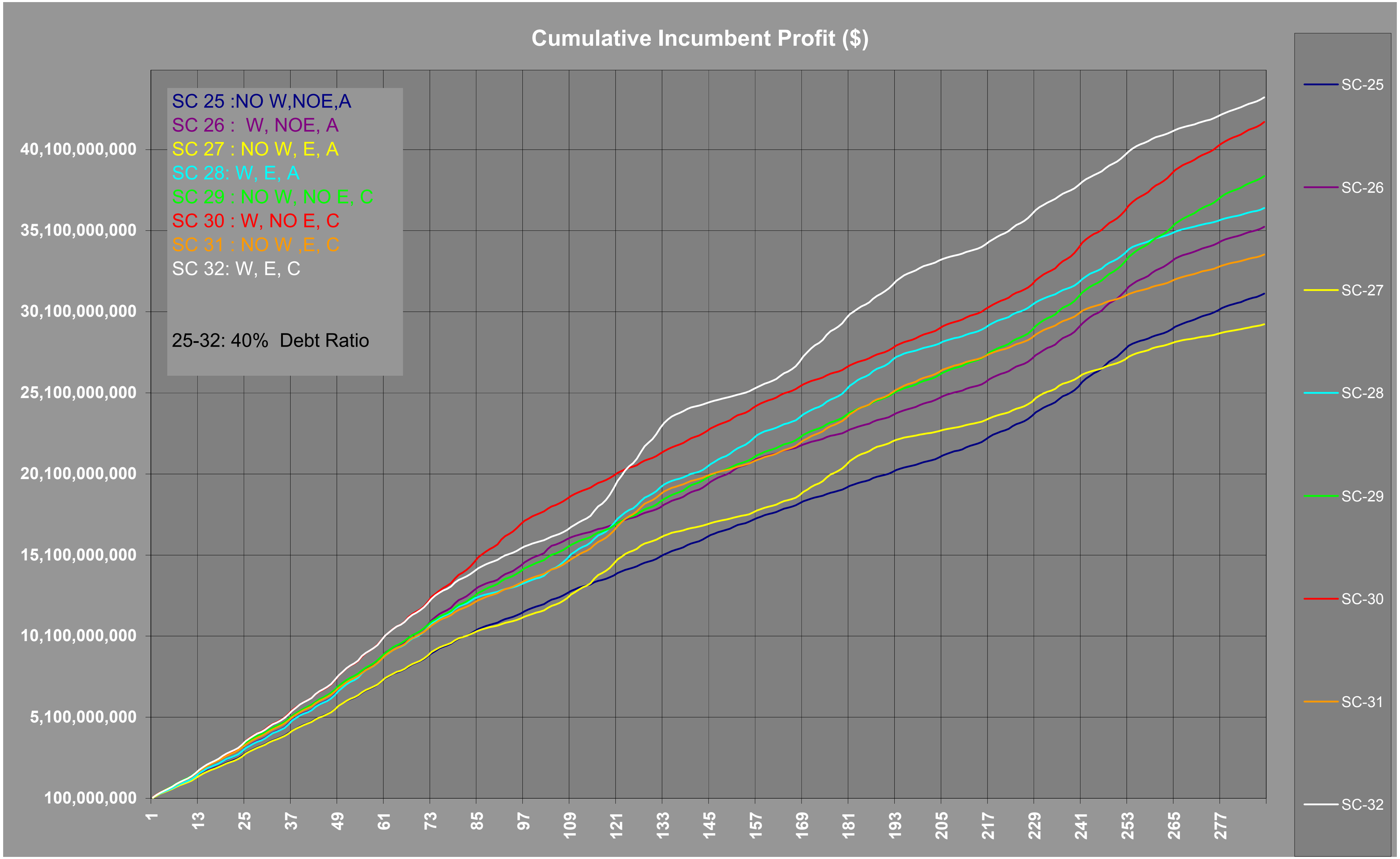
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24


Cumulative Incumbent Profit ($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
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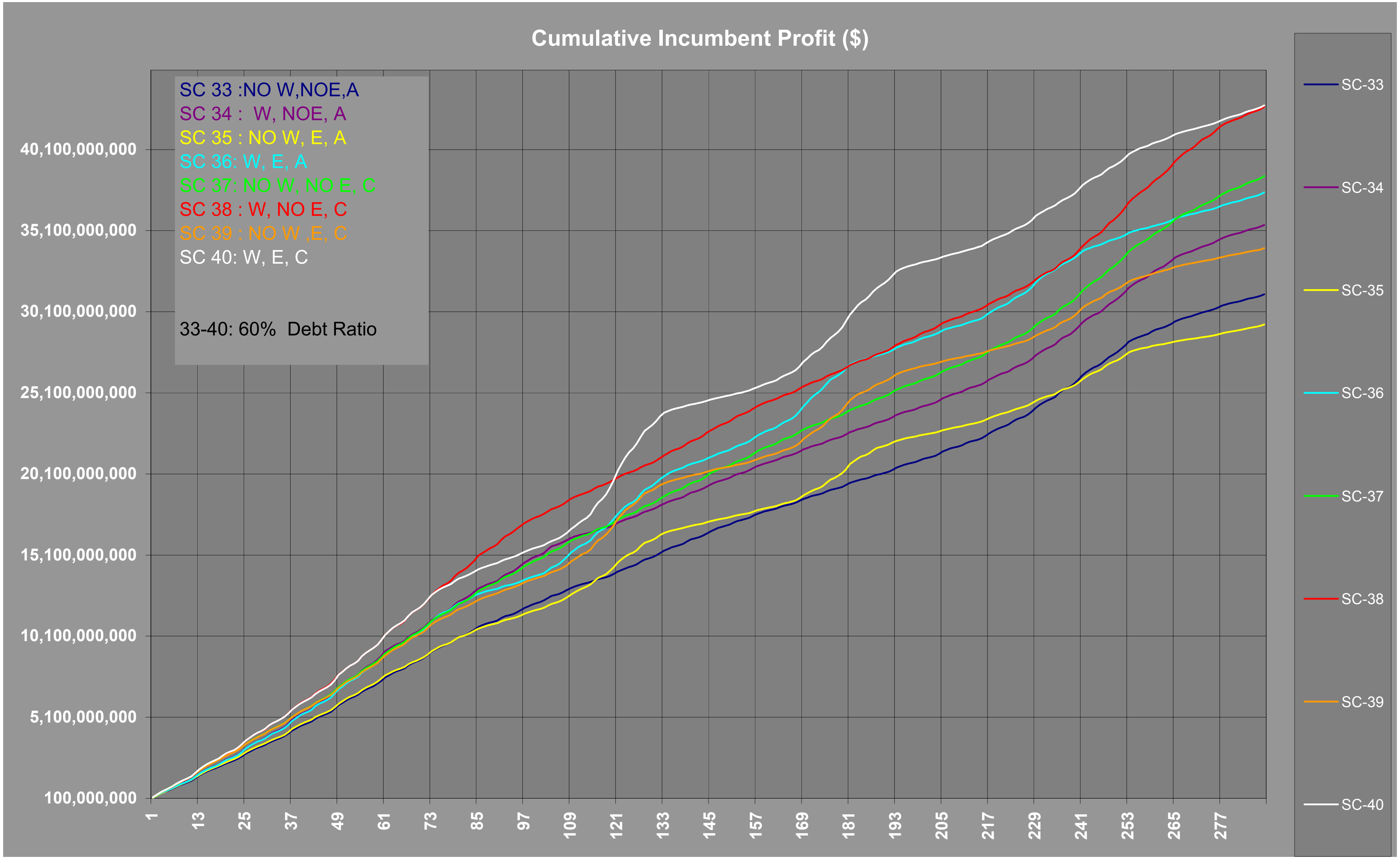
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32


Cumulative Incumbent Profit ($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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SC-33
SC-34
SC-35
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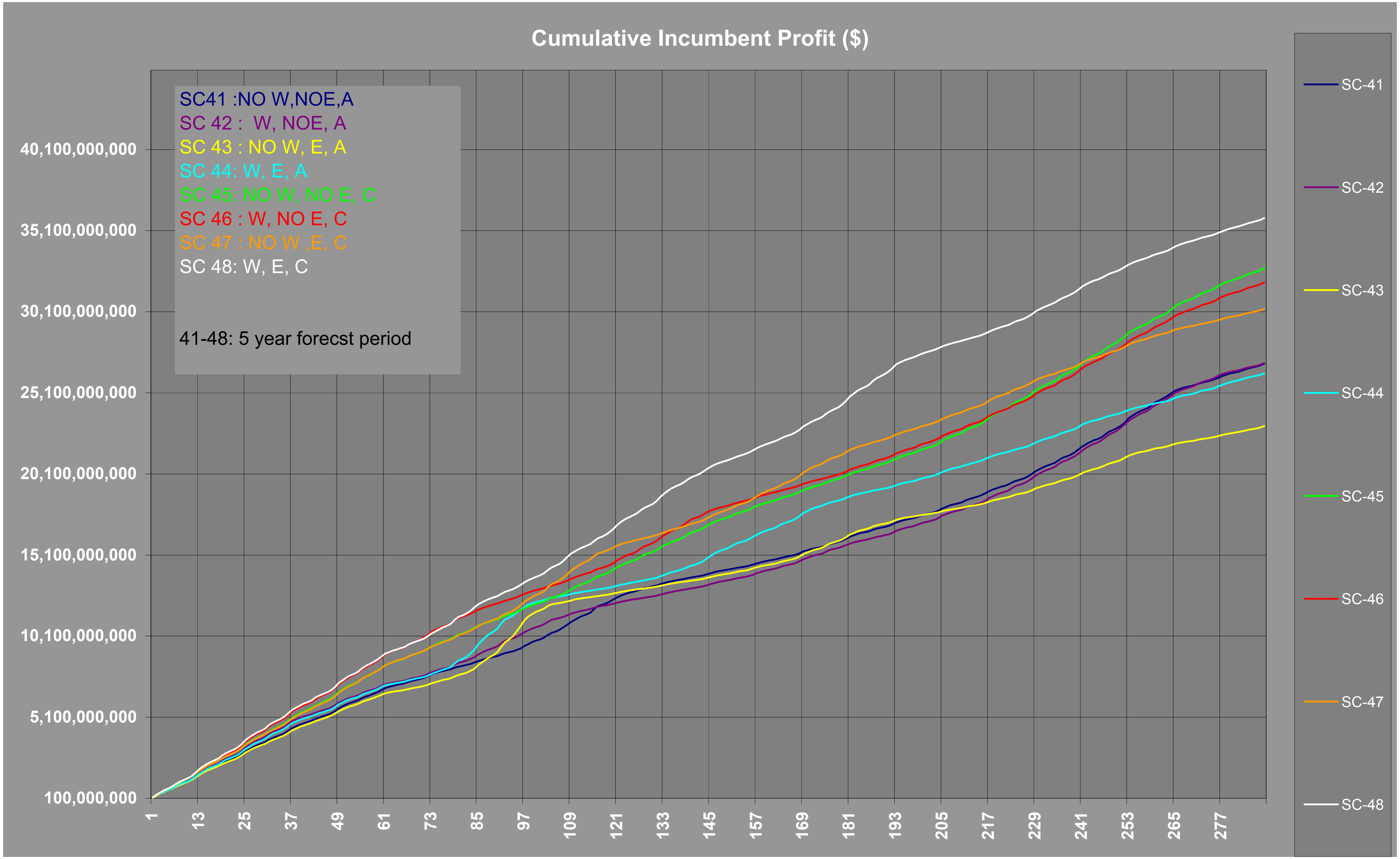
SC-38
SC-39
SC-40



Cumulative Incumbent Profit ($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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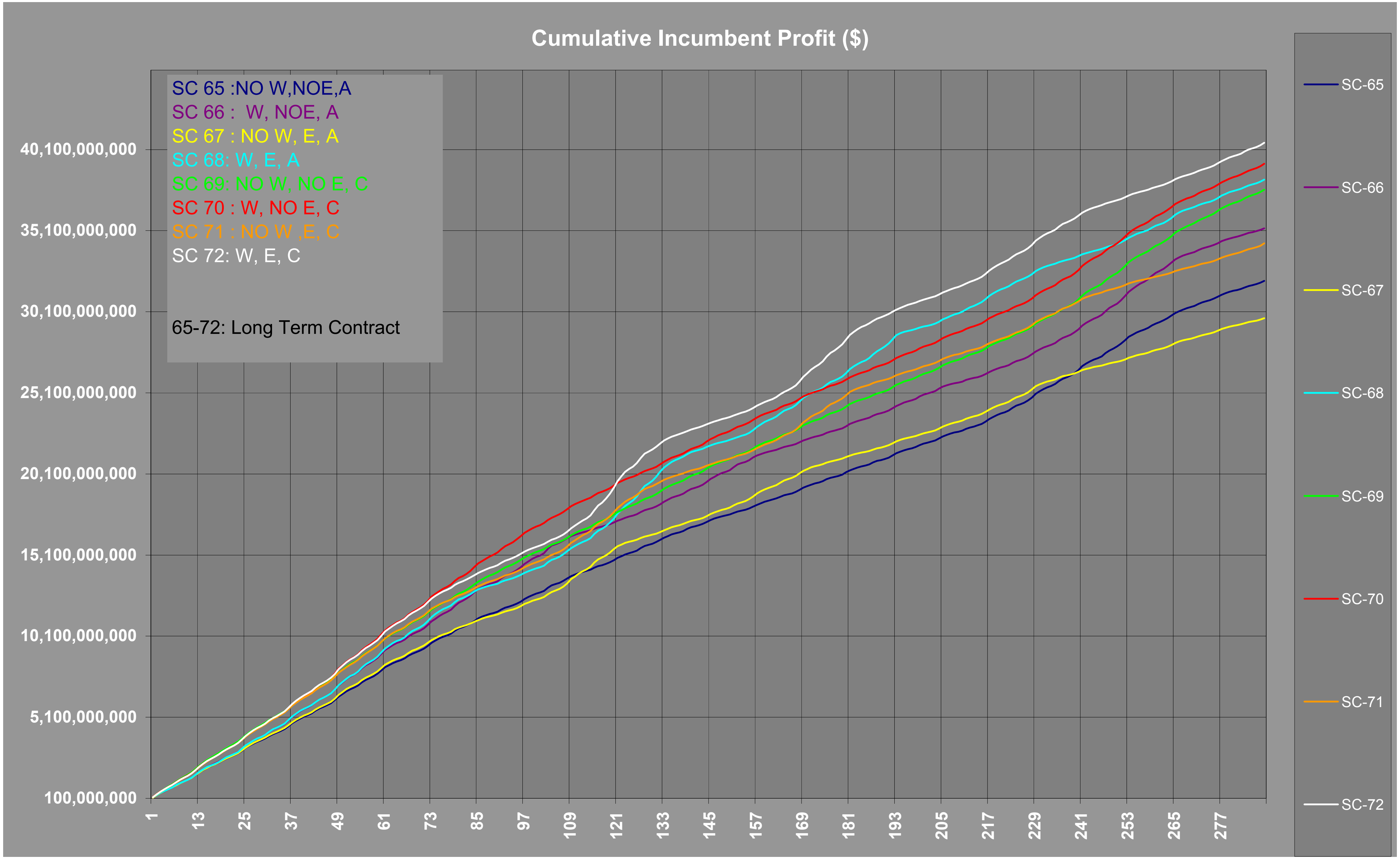
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



Cumulative Incumbent Profit ($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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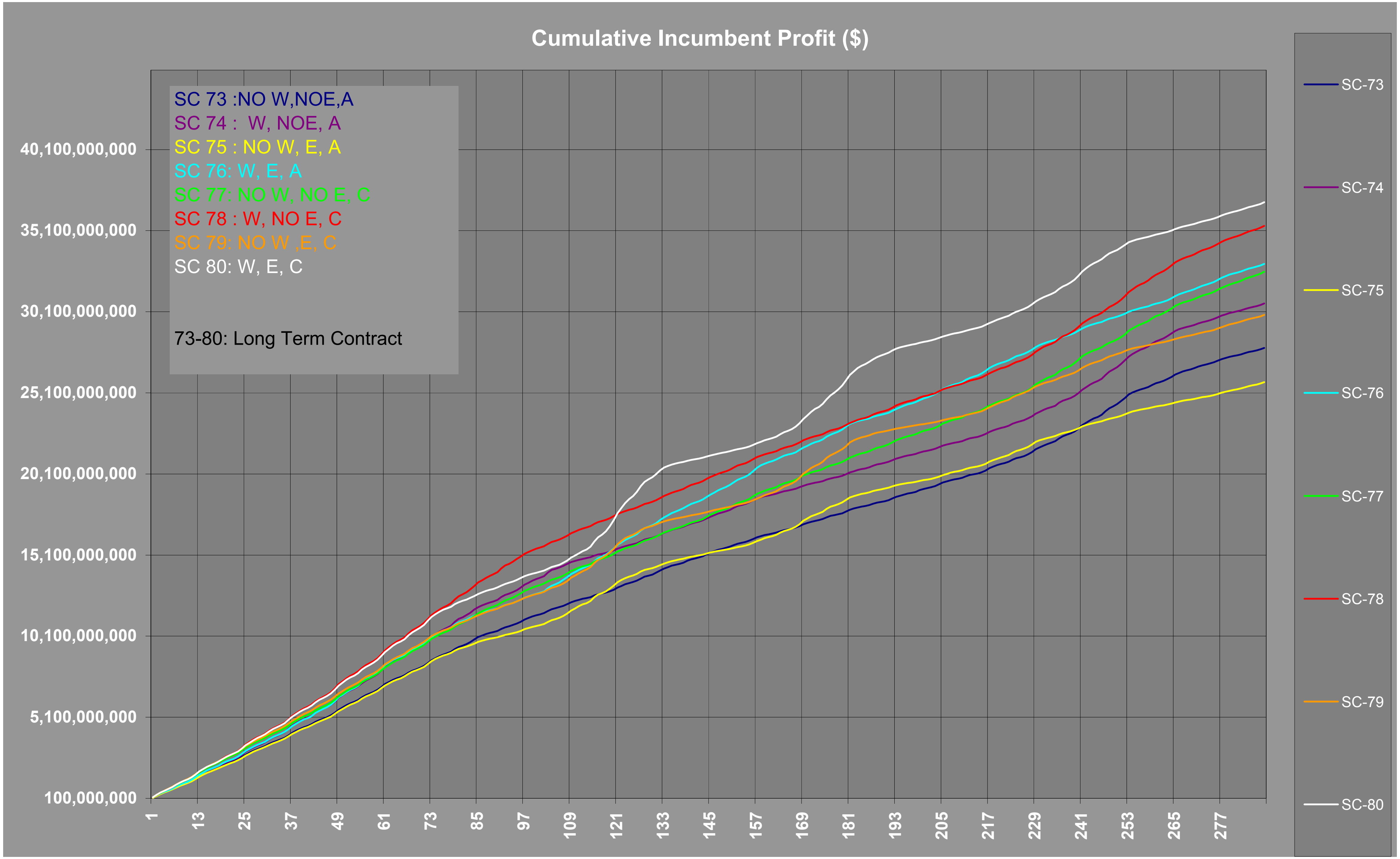
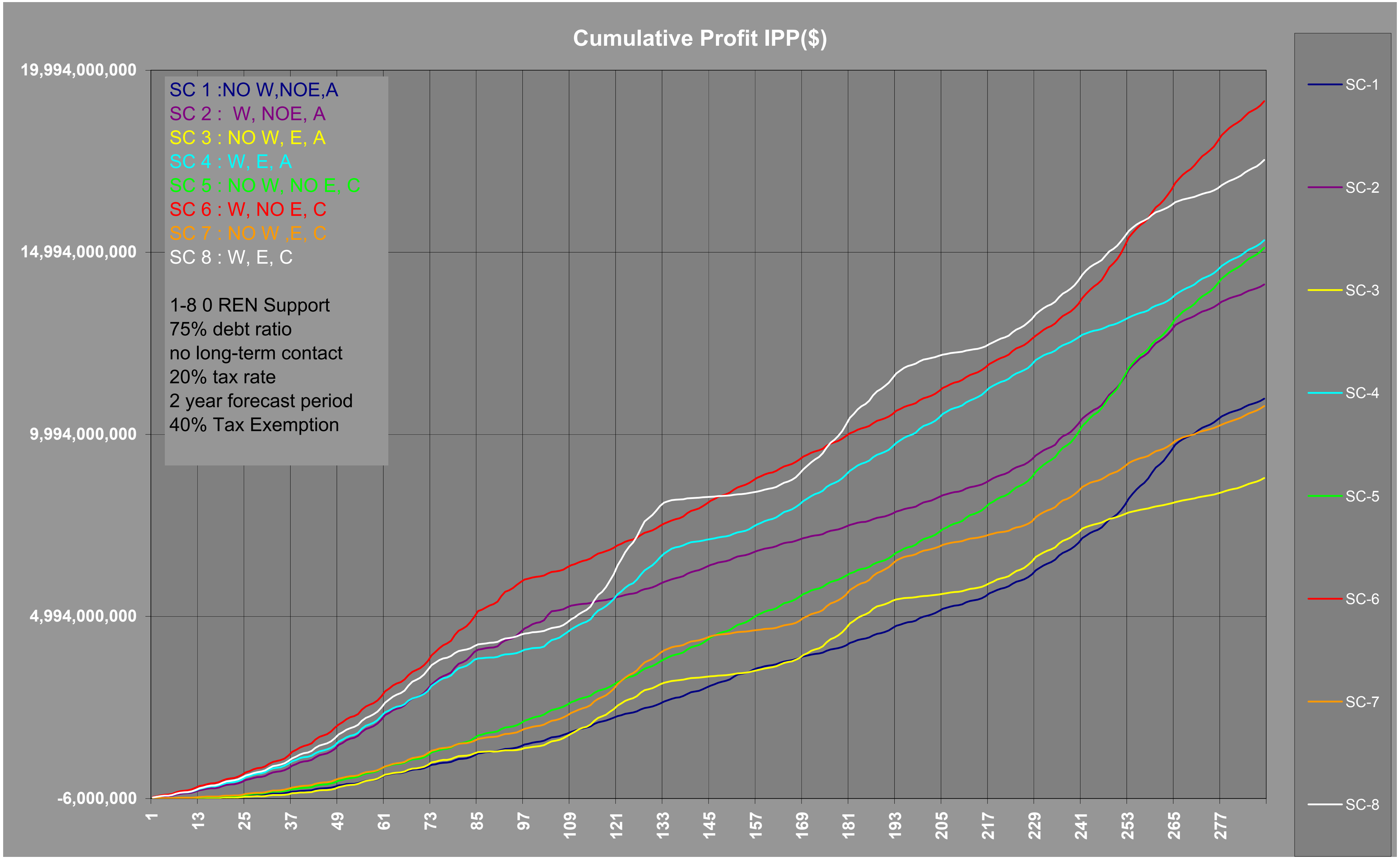
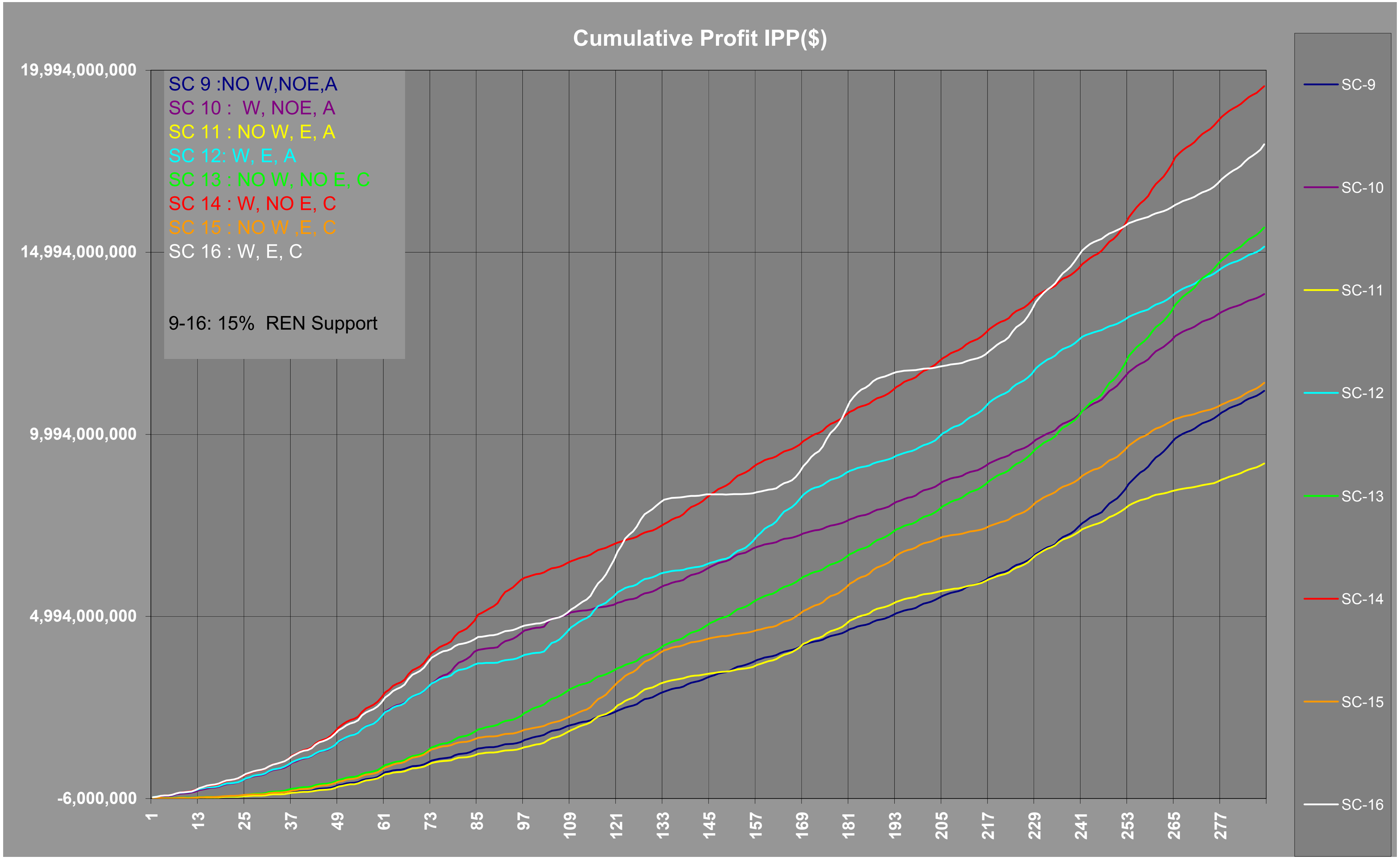
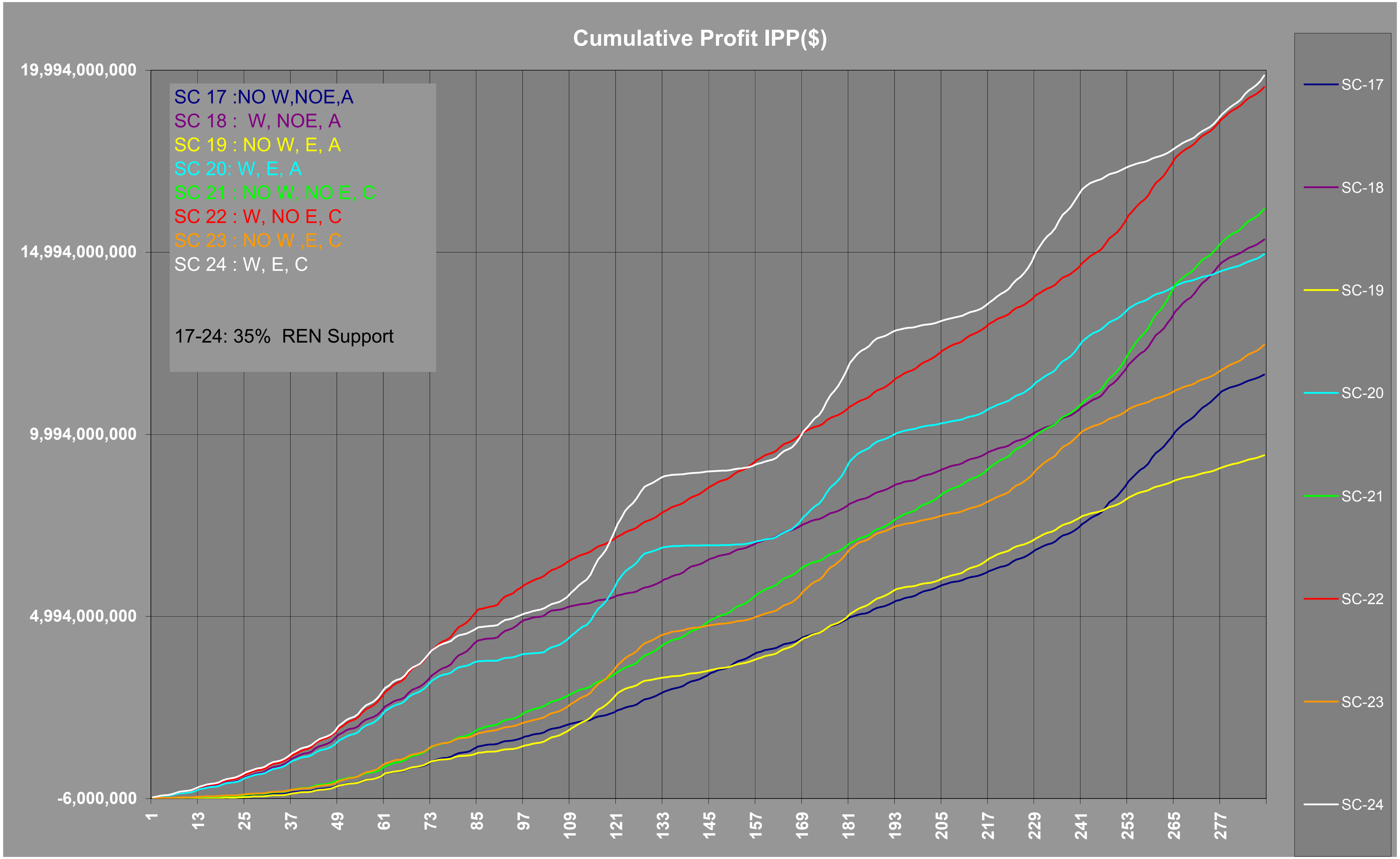
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

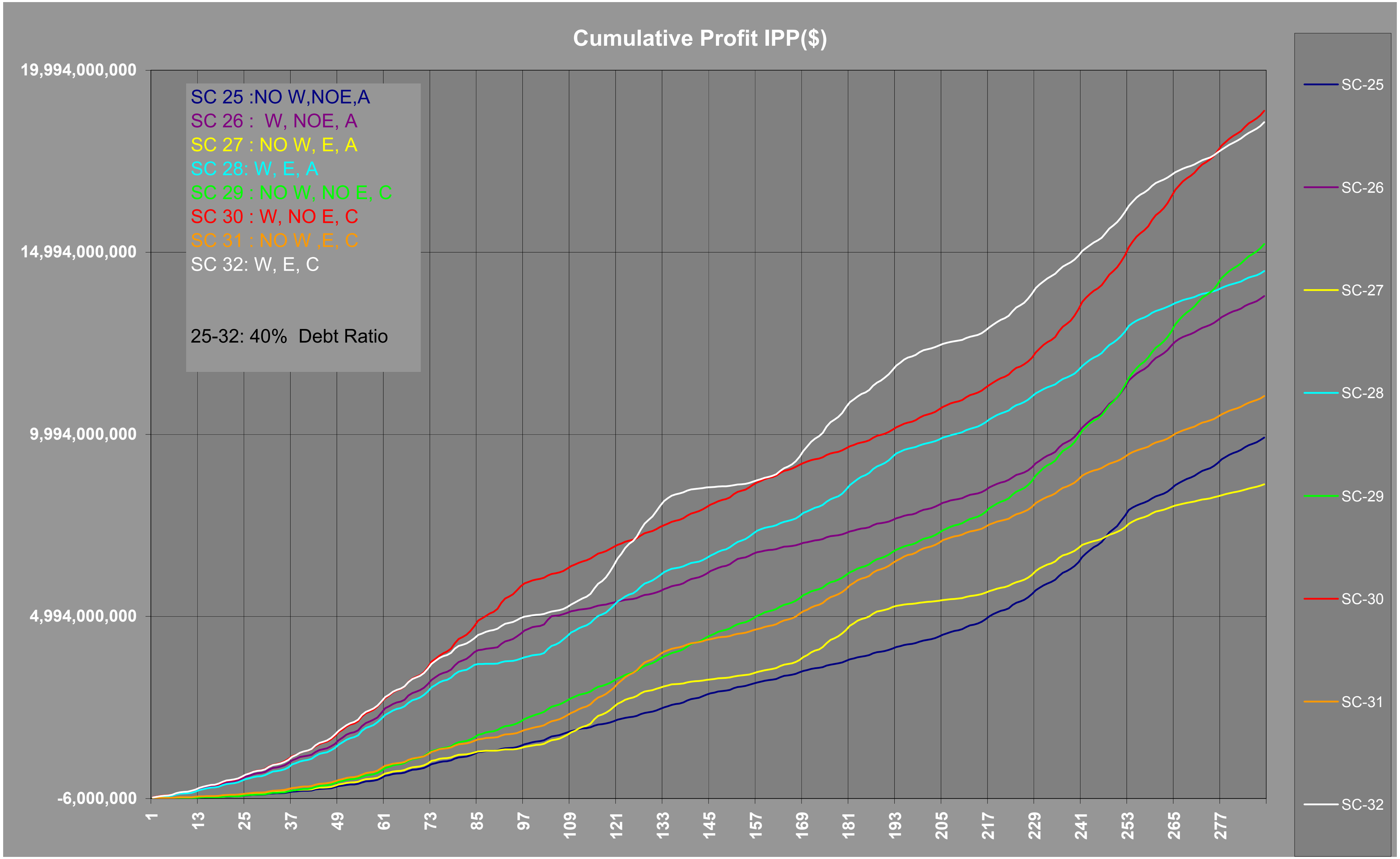

Cumulative Incumbent Profit ($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1 13 25 37 49 61 73 85 97 109 121 133 145 157 169 181 193 205 217 229 241 253 265 277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

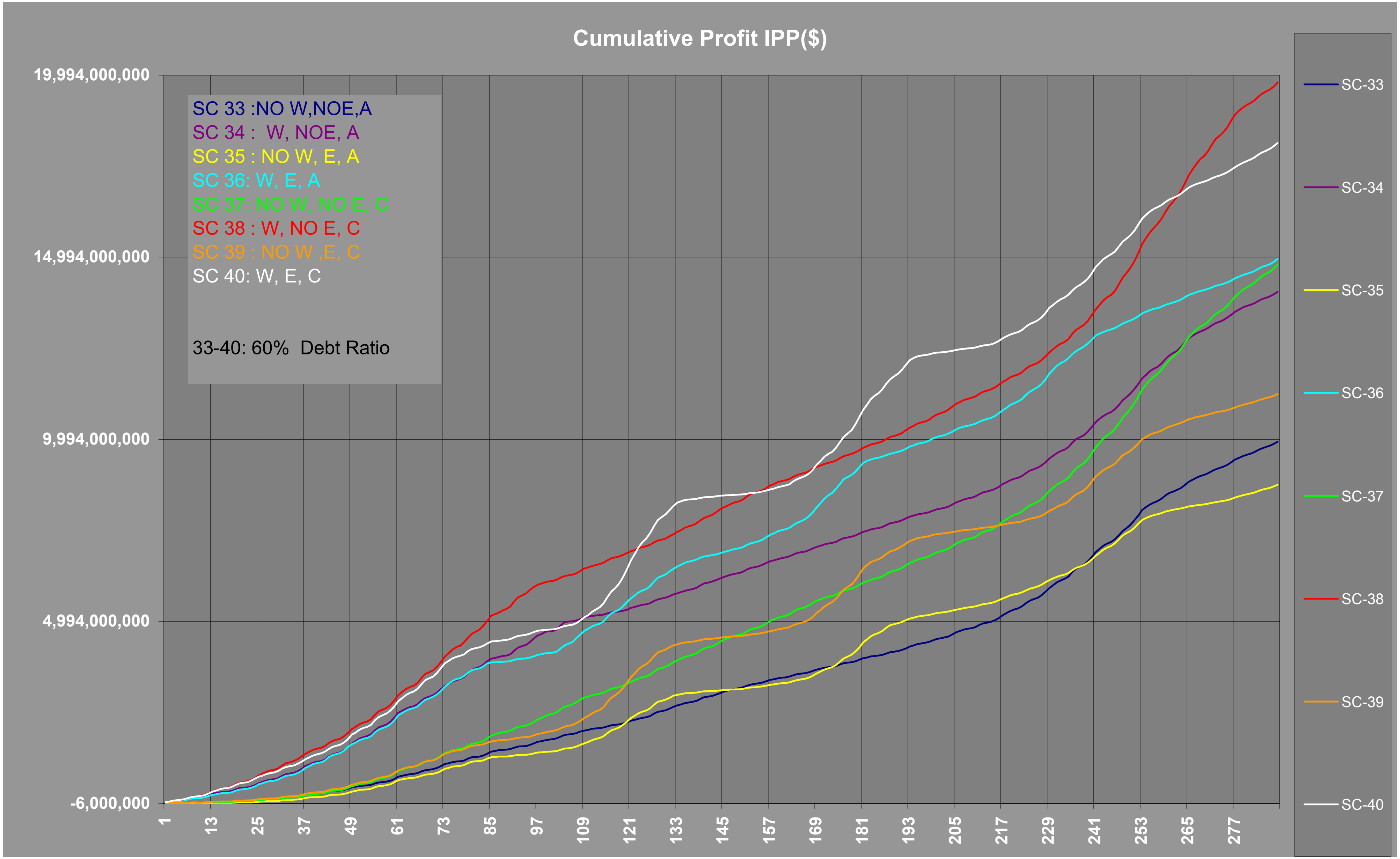

Cumulative Profit IPP($)
19,994,000,000
14,994,000,000
9,994,000,000
4,994,000,000
-6,000,000
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

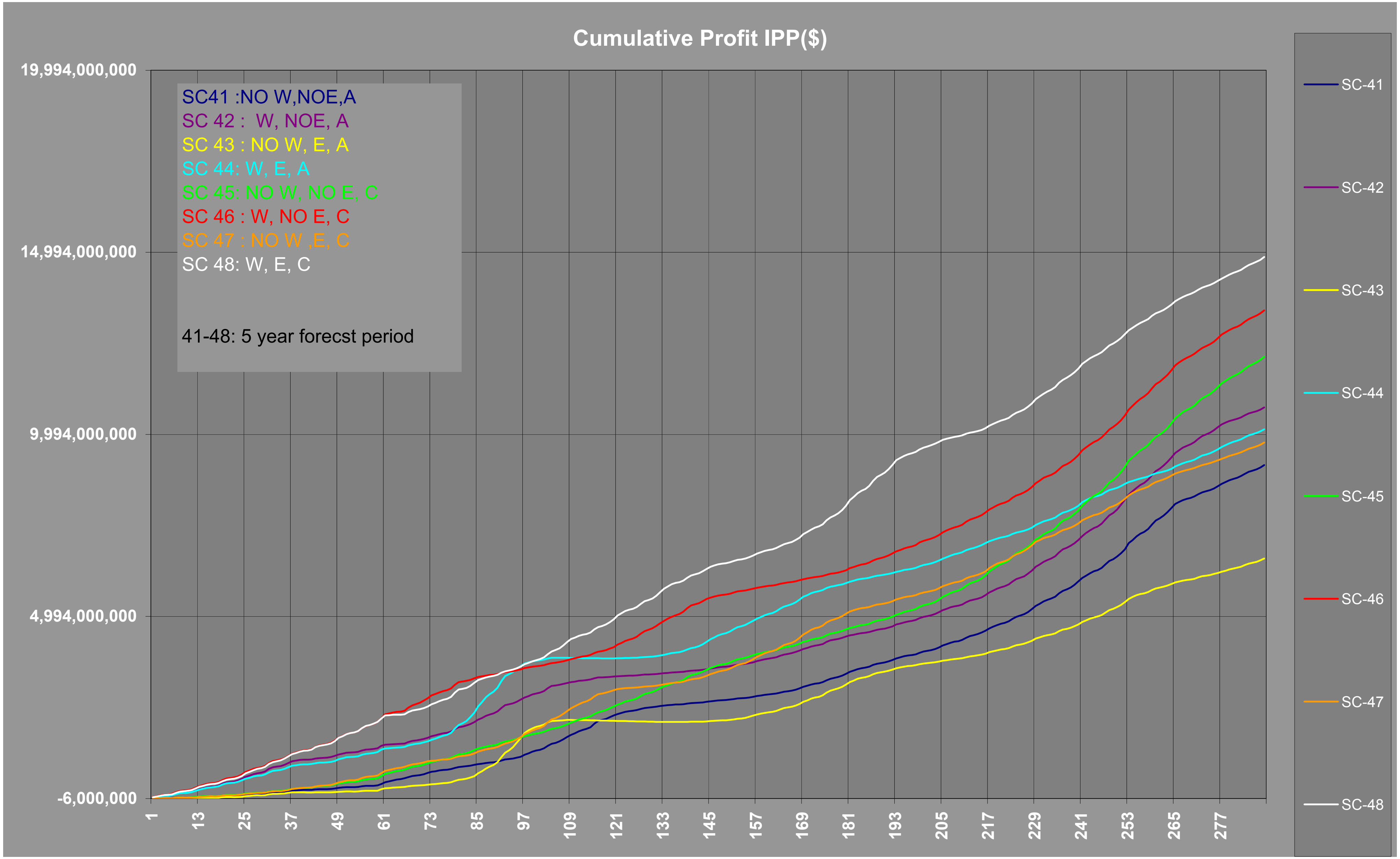

Cumulative Profit IPP($)
19,994,000,000
14,994,000,000
9,994,000,000
4,994,000,000
-6,000,000
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



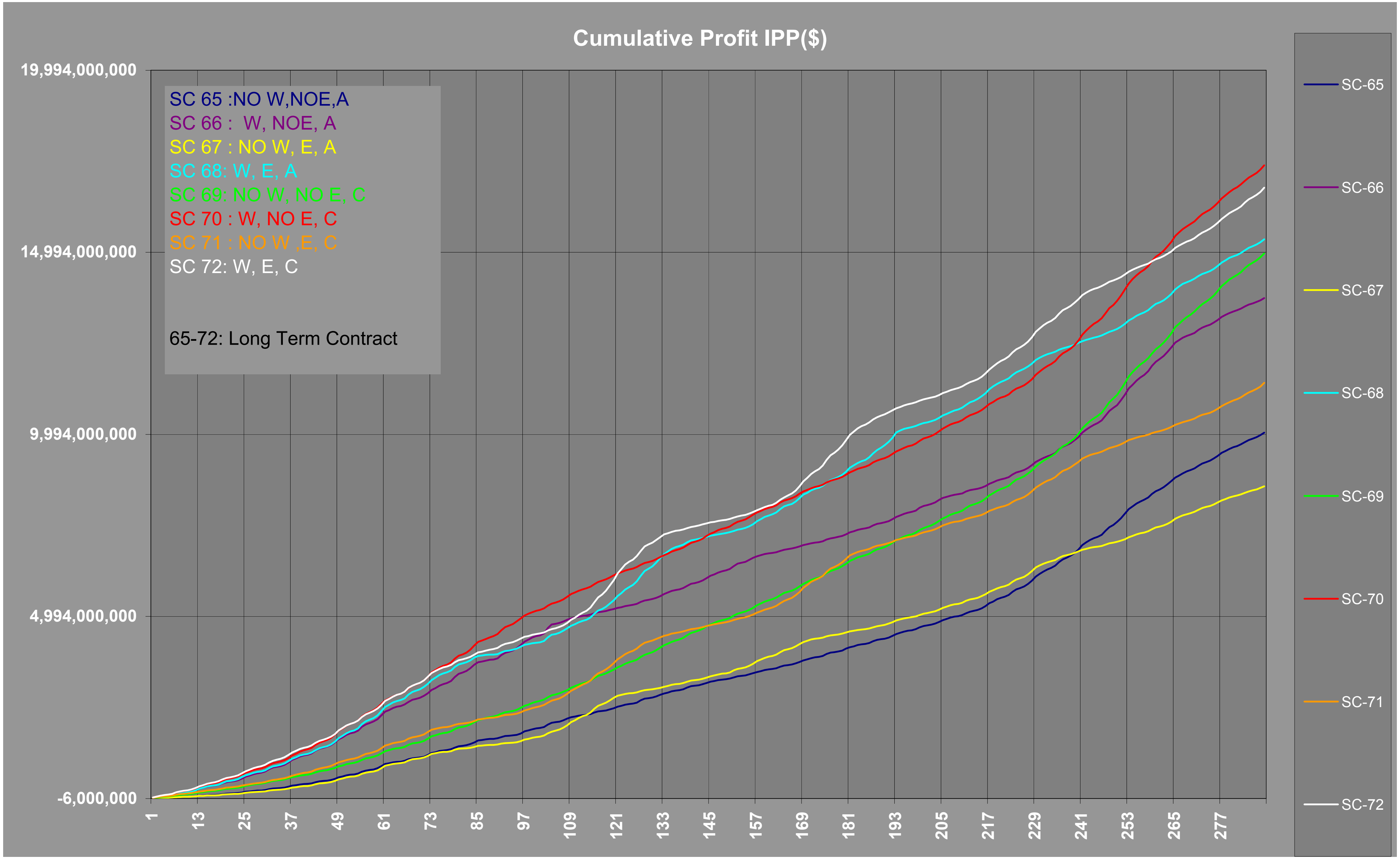
Cumulative Profit IPP($)
19,994,000,000
14,994,000,000
9,994,000,000
4,994,000,000
-6,000,000
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24

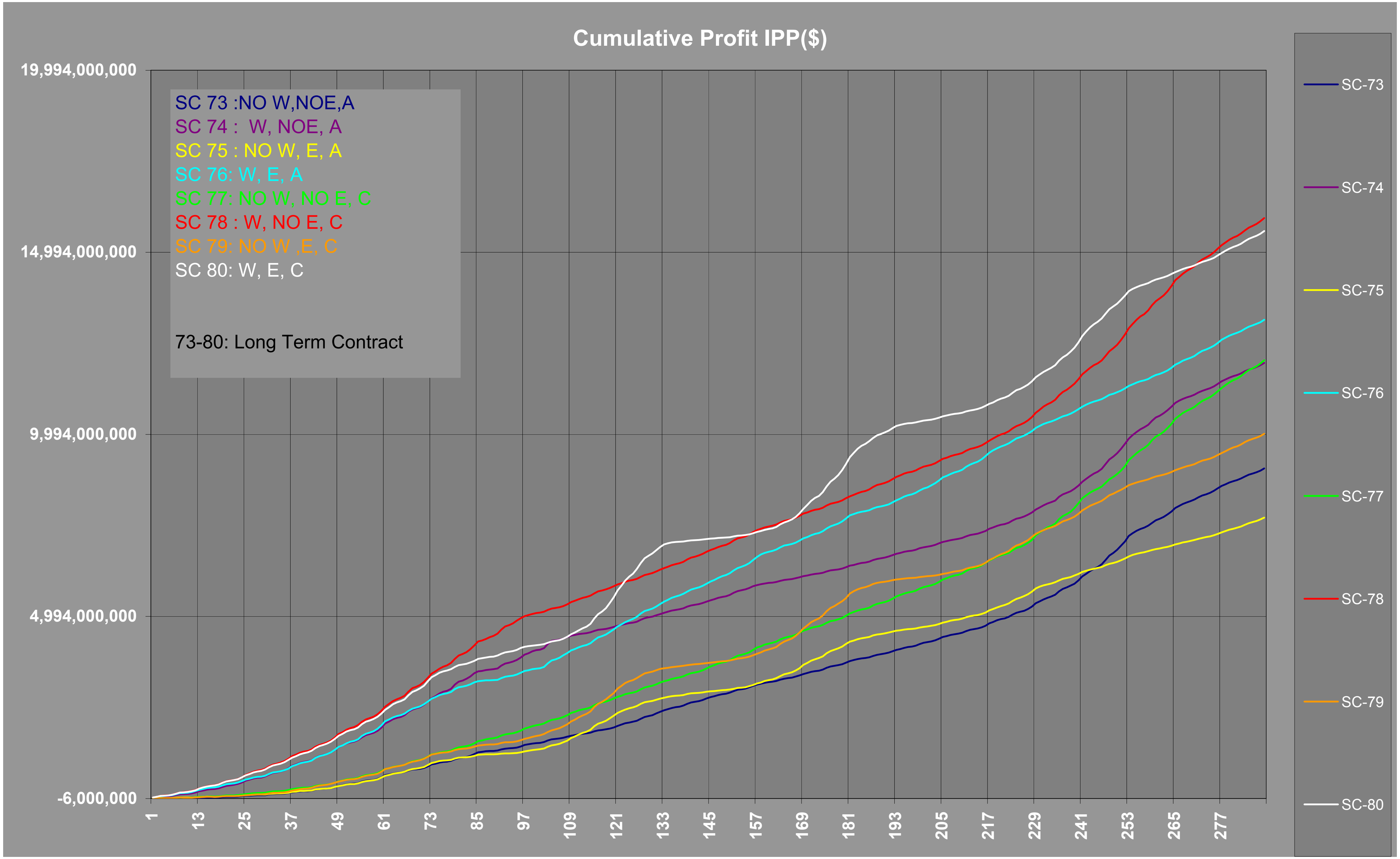

Cumulative Profit IPP($)
19,994,000,000
14,994,000,000
9,994,000,000
4,994,000,000
-6,000,000
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32


Cumulative Profit IPP($)
19,994,000,000
14,994,000,000
9,994,000,000
4,994,000,000
-6,000,000
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

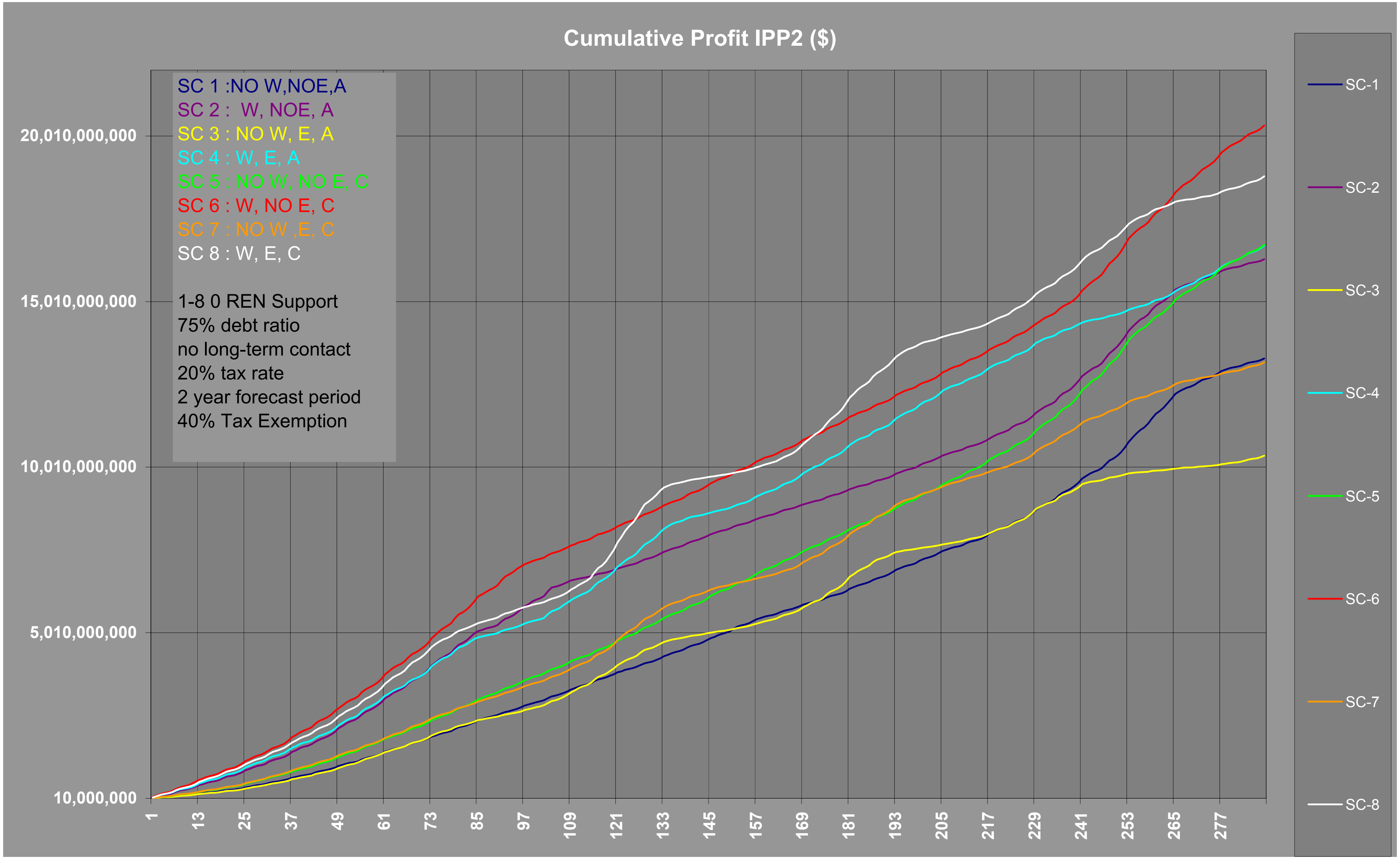


Cumulative Profit IPP($)
19,994,000,000
14,994,000,000
9,994,000,000
4,994,000,000
-6,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48

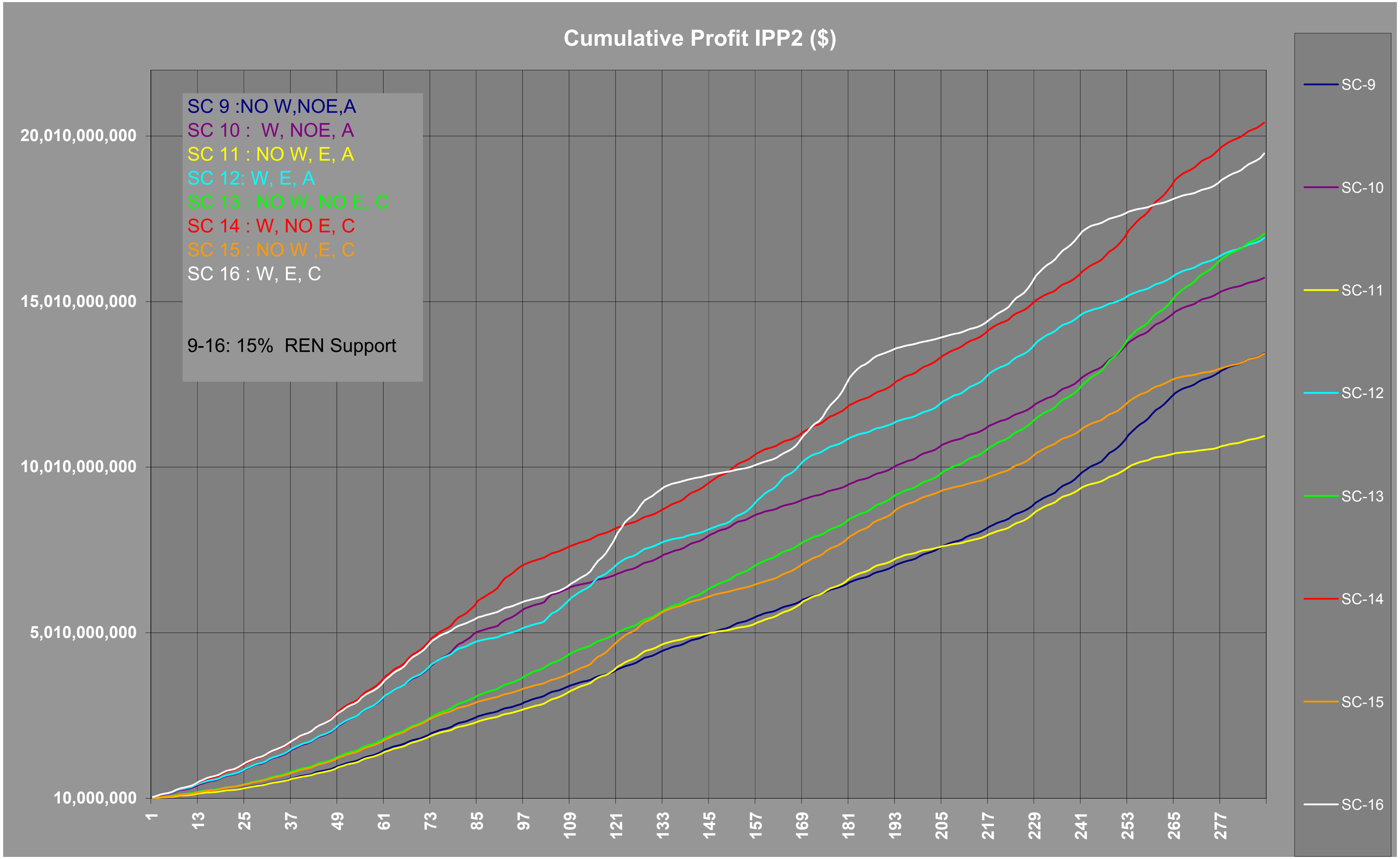

Cumulative Profit IPP($)
19,994,000,000
14,994,000,000
9,994,000,000
4,994,000,000
-6,000,000
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



Cumulative Profit IPP($)
19,994,000,000
14,994,000,000
9,994,000,000
4,994,000,000
-6,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



Cumulative Profit IPP2 ($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
20,010,000,000
15,010,000,000
10,010,000,000
5,010,000,000
10,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8


Cumulative Profit IPP2 ($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
20,010,000,000
15,010,000,000
10,010,000,000
5,010,000,000
10,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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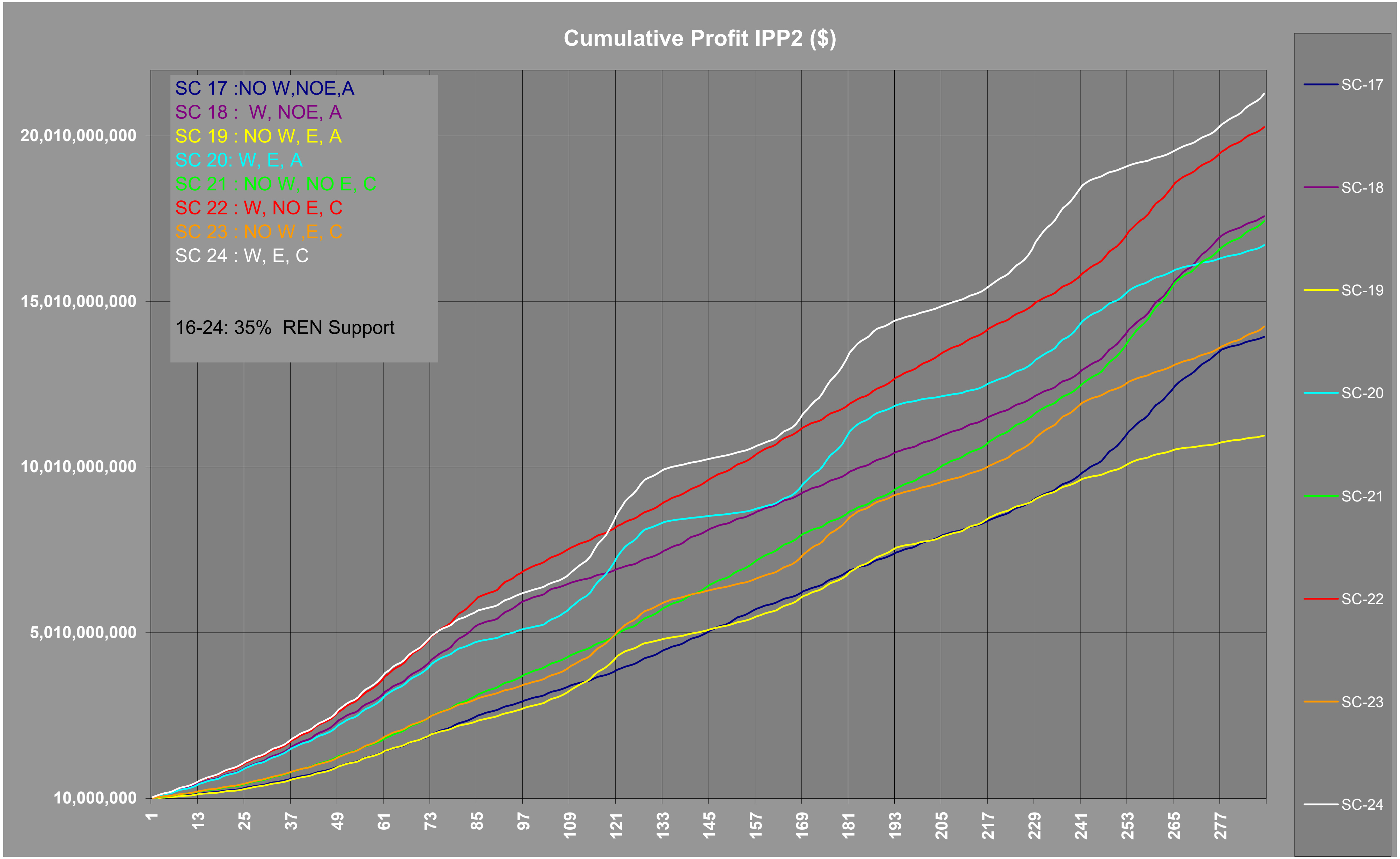
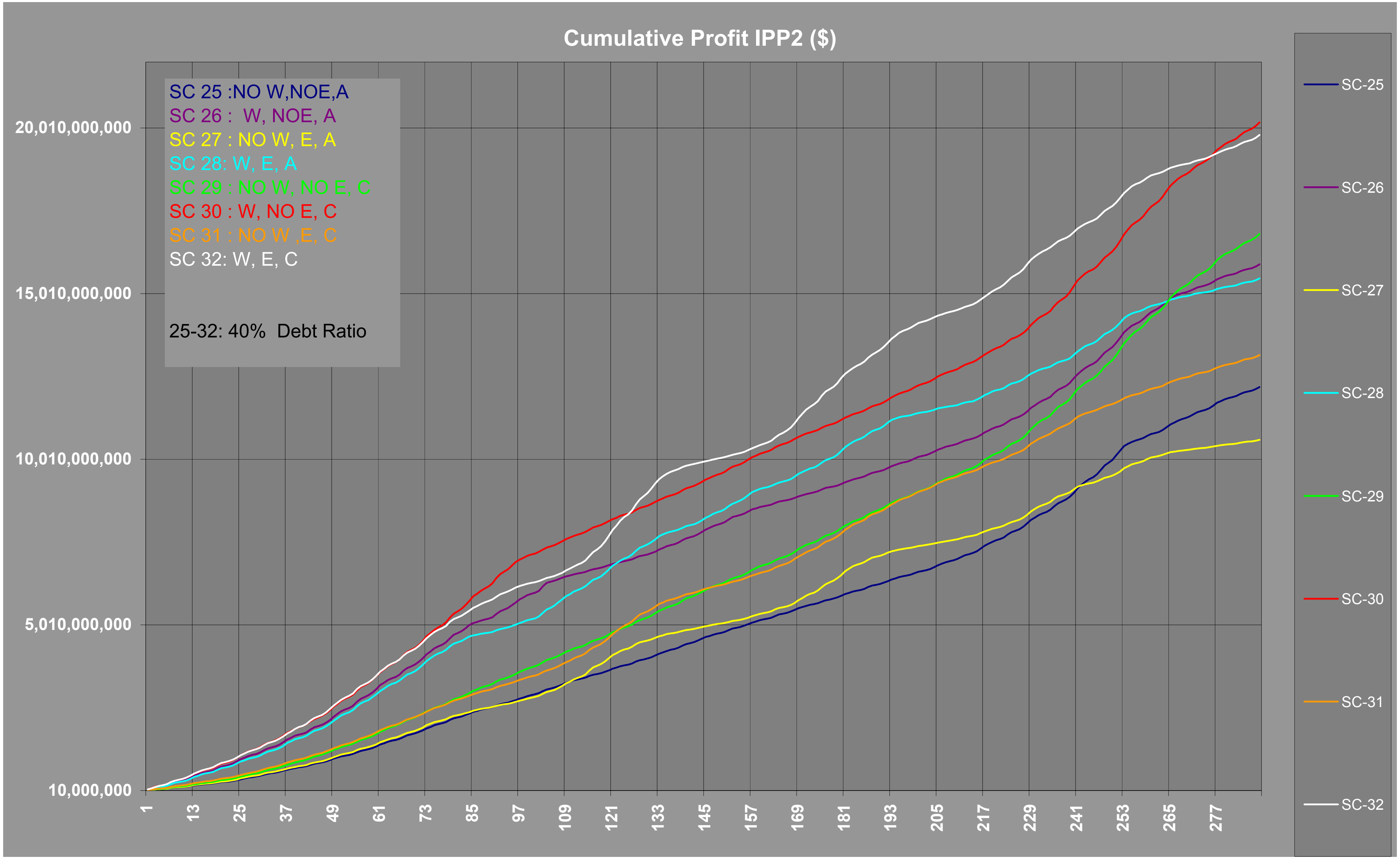
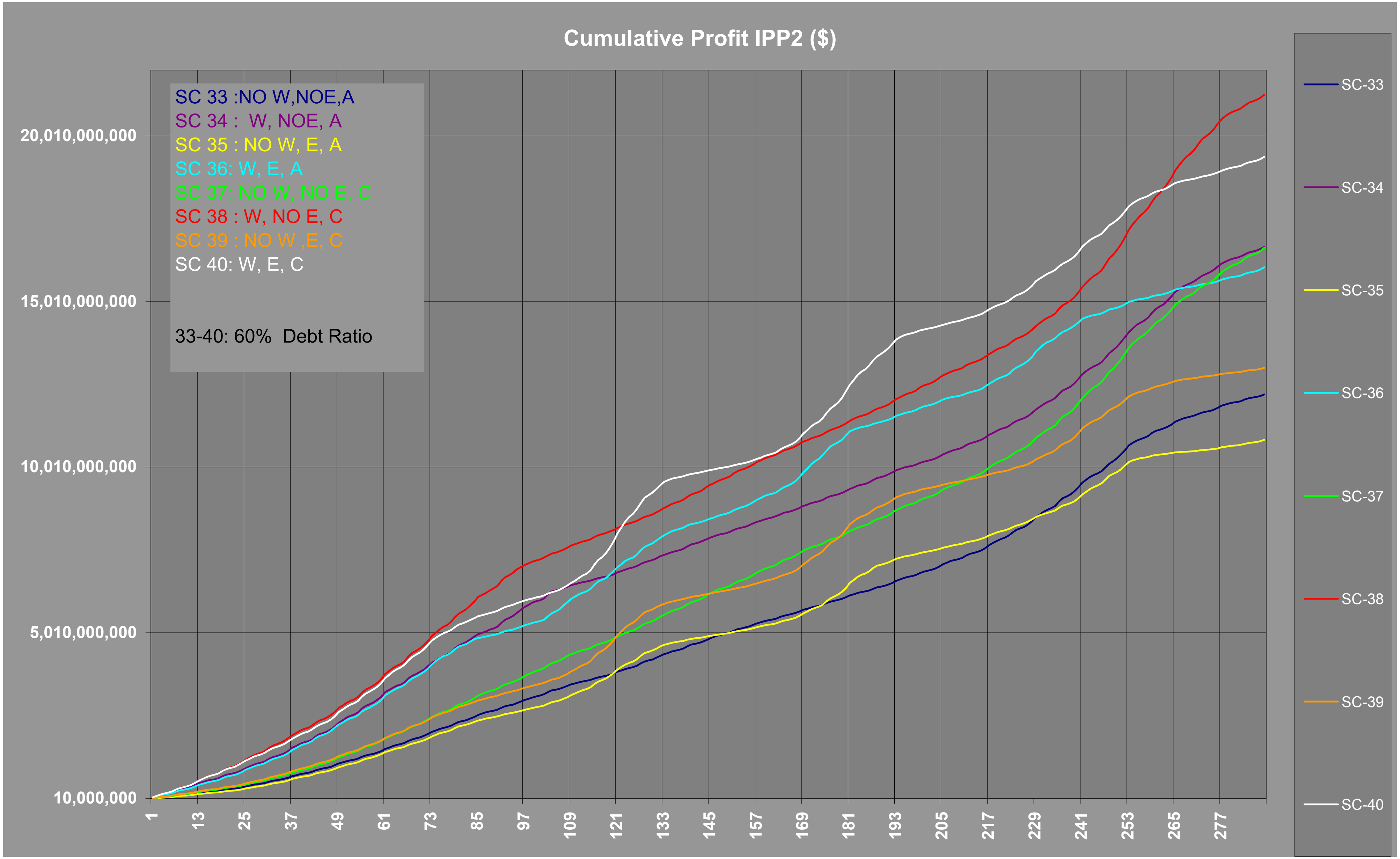
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



Cumulative Profit IPP2 ($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
16-24: 35% REN Support
20,010,000,000
15,010,000,000
10,010,000,000
5,010,000,000
10,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24



Cumulative Profit IPP2 ($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
20,010,000,000
15,010,000,000
10,010,000,000
5,010,000,000
10,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



Cumulative Profit IPP2 ($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
20,010,000,000
15,010,000,000
10,010,000,000
5,010,000,000
10,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
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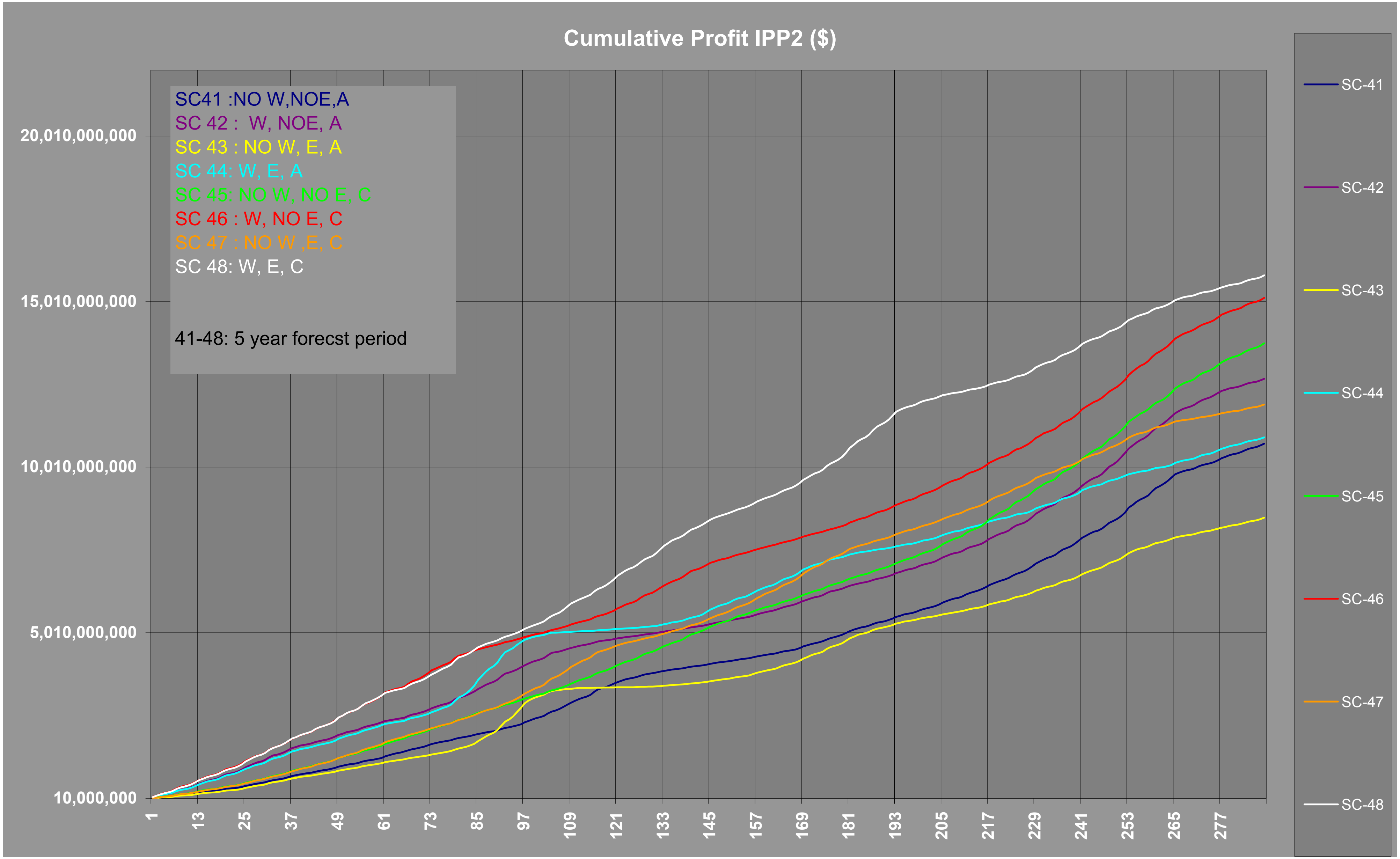
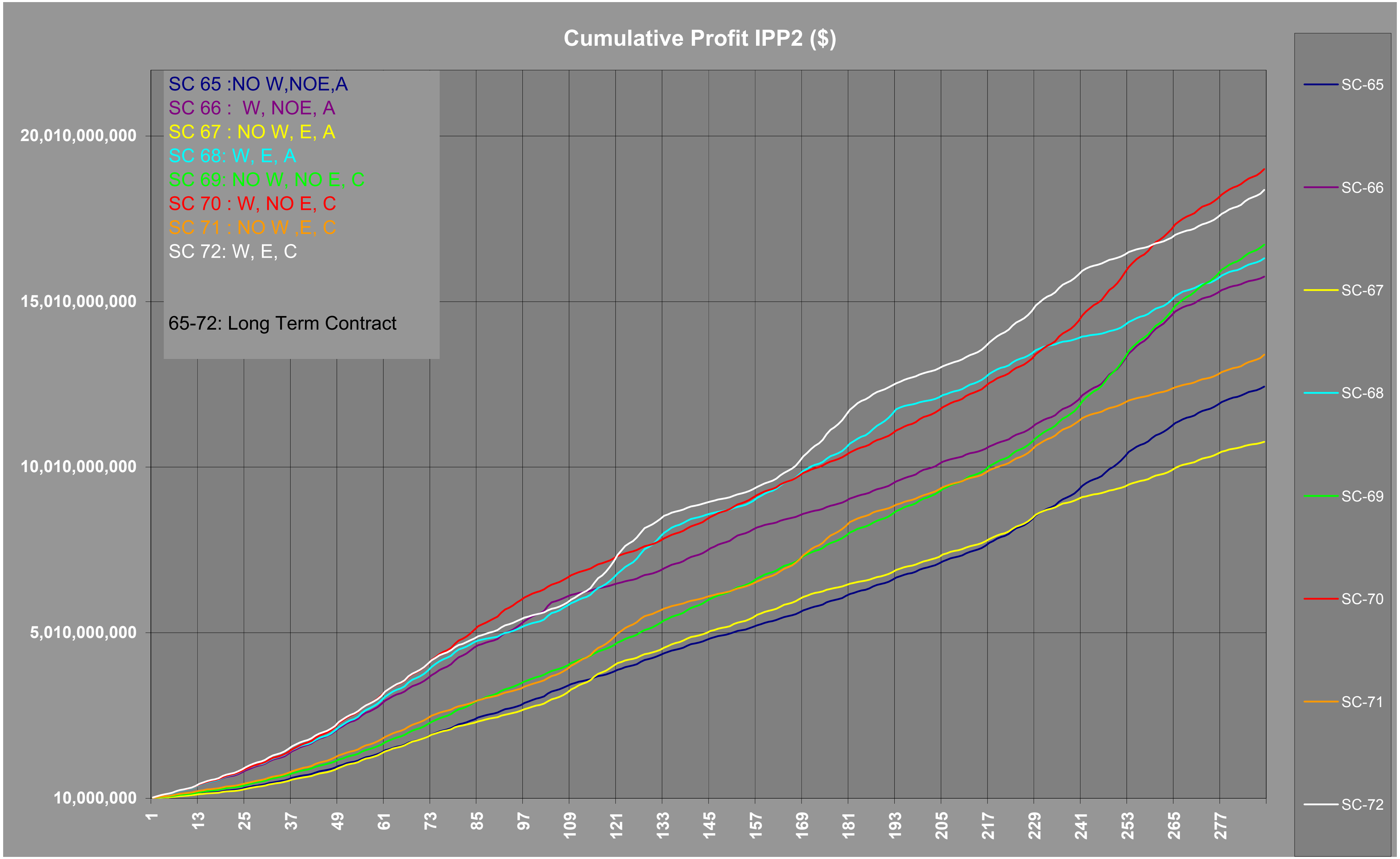
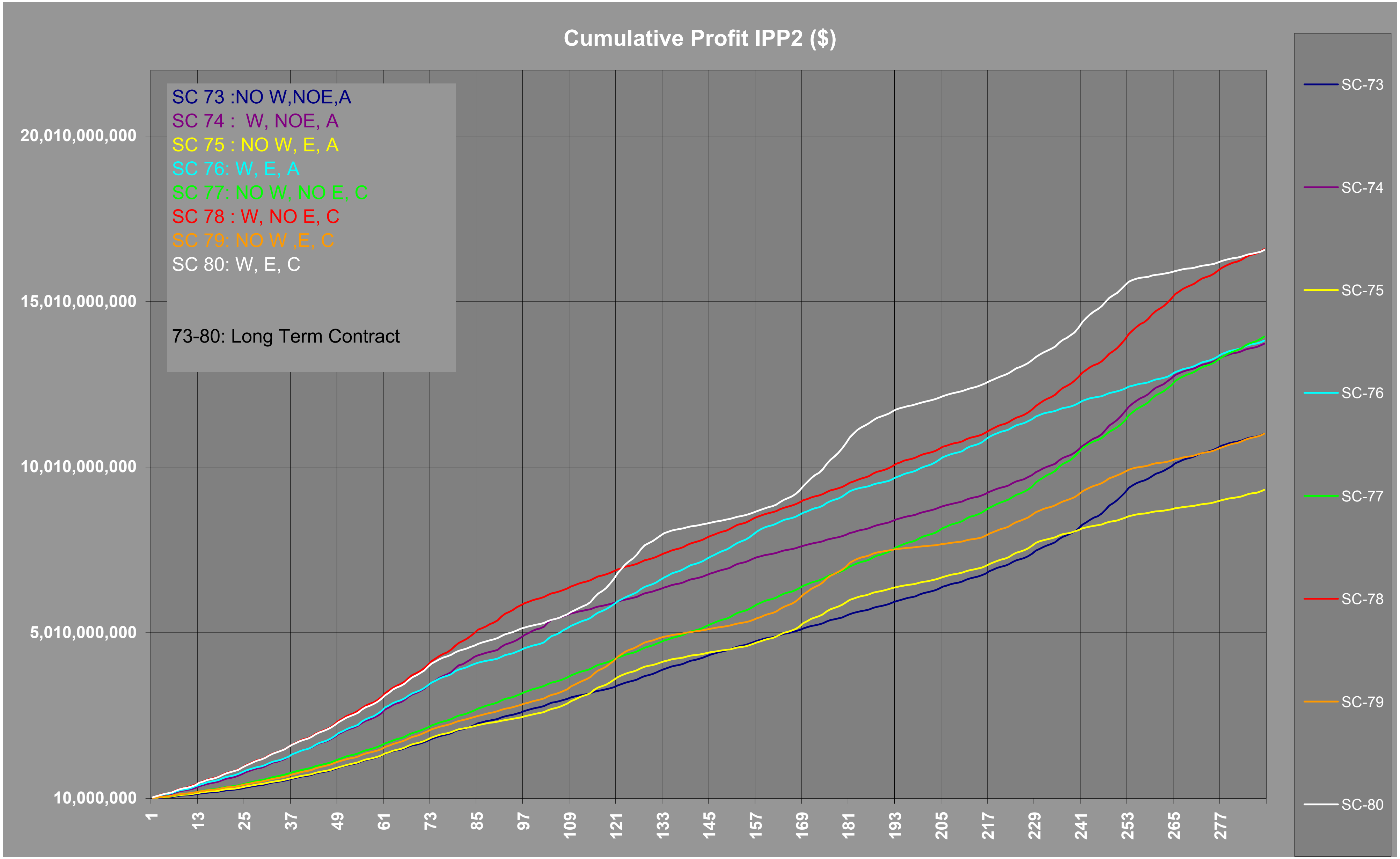
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



Cumulative Profit IPP2 ($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
20,010,000,000
15,010,000,000
10,010,000,000
5,010,000,000
10,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



Cumulative Profit IPP2 ($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
20,010,000,000
15,010,000,000
10,010,000,000
5,010,000,000
10,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



Cumulative Profit IPP2 ($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
20,010,000,000
15,010,000,000
10,010,000,000
5,010,000,000
10,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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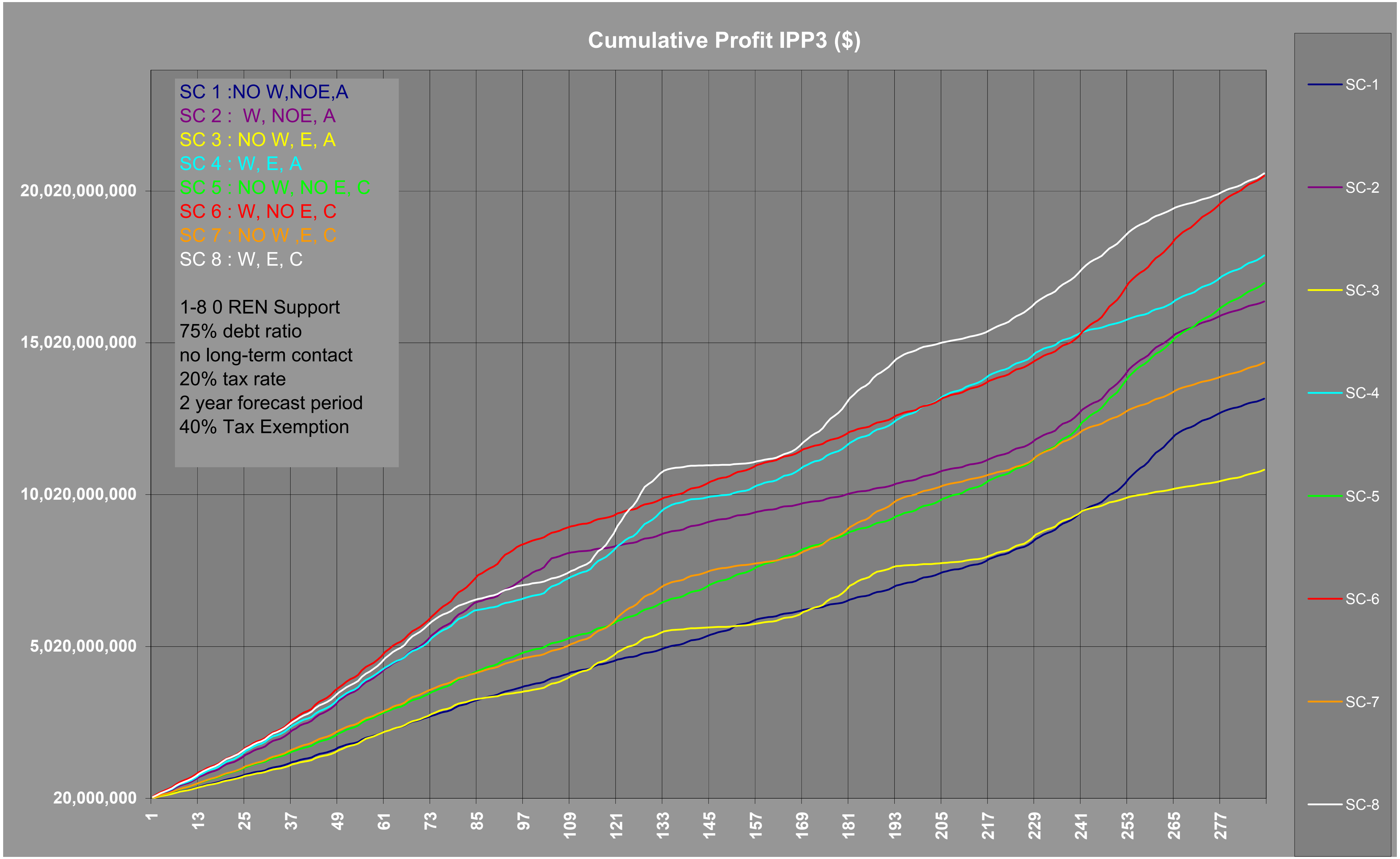
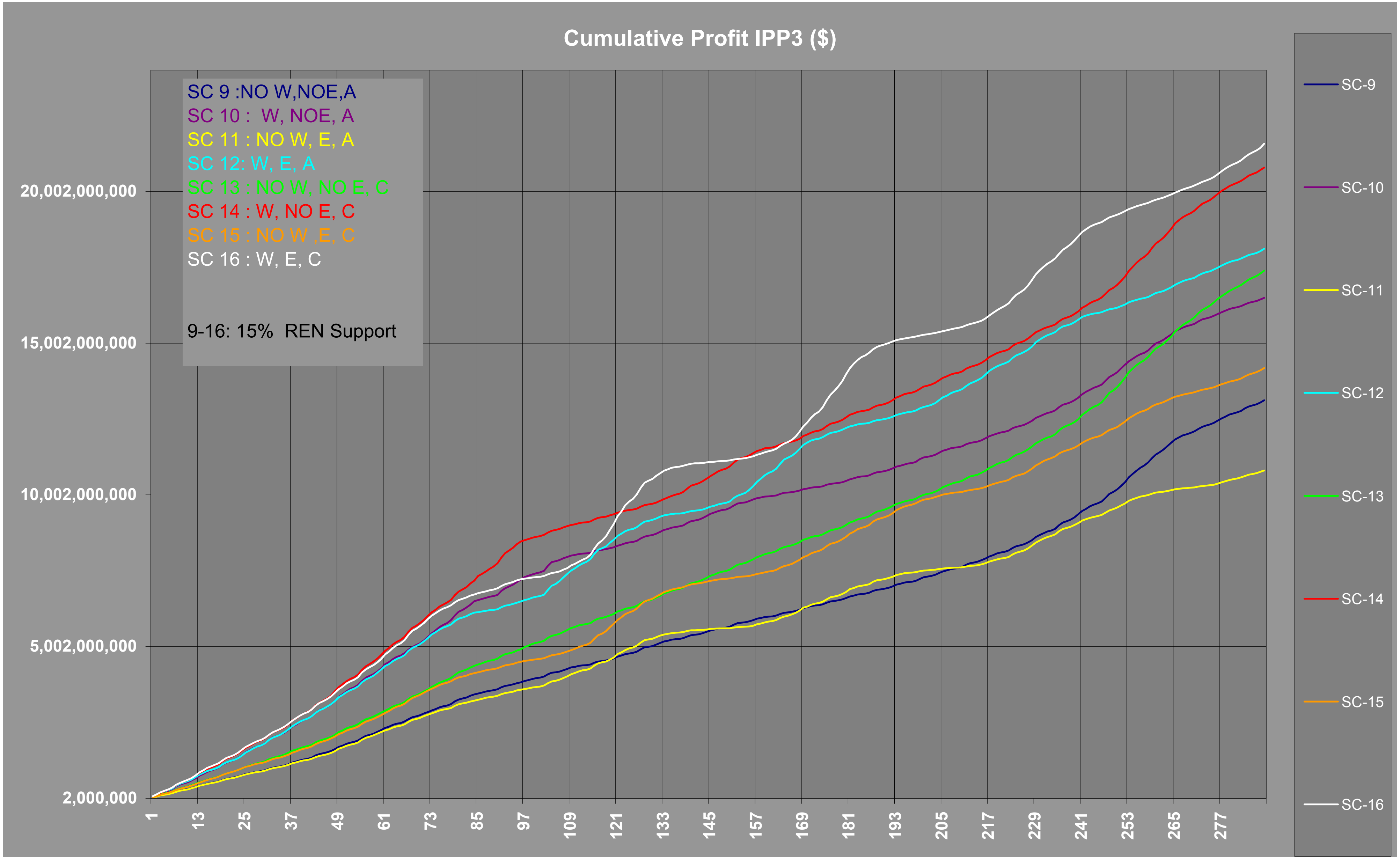
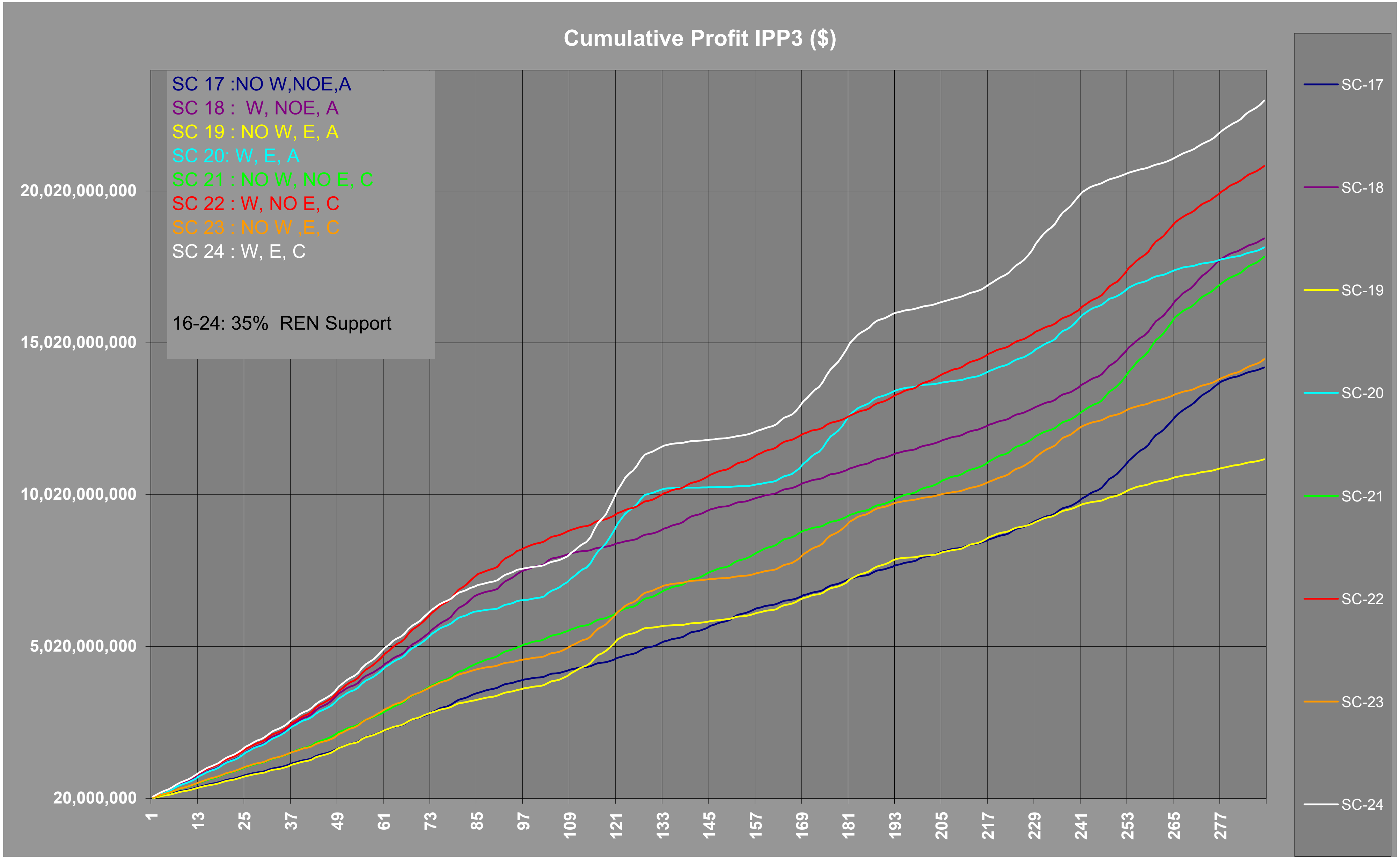
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

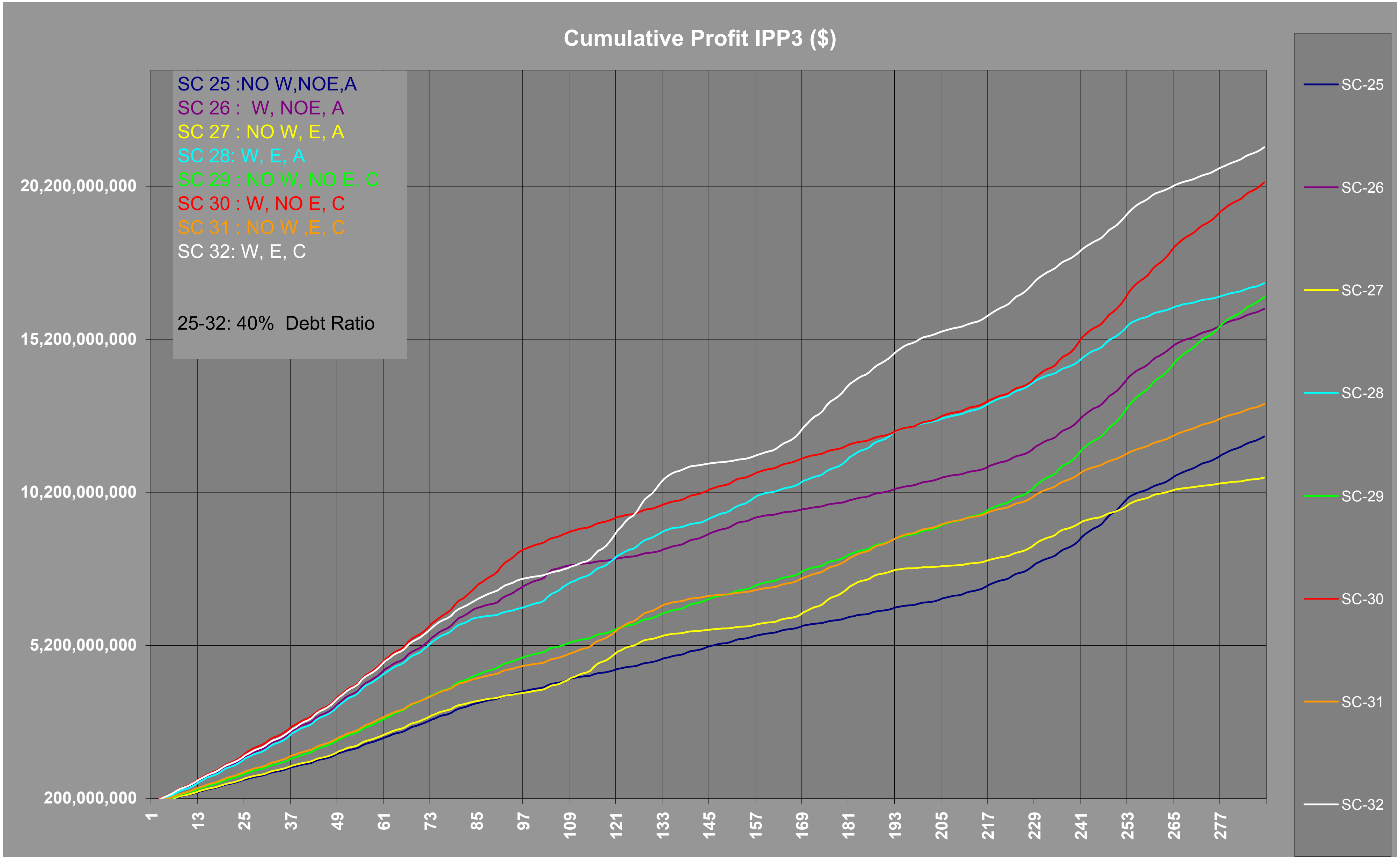


Cumulative Profit IPP3 ($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Cumulative Profit IPP3 ($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
20,002,000,000
15,002,000,000
10,002,000,000
5,002,000,000
2,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16


Cumulative Profit IPP3 ($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
16-24: 35% REN Support
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24



Cumulative Profit IPP3 ($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
20,200,000,000
15,200,000,000
10,200,000,000
5,200,000,000
200,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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229
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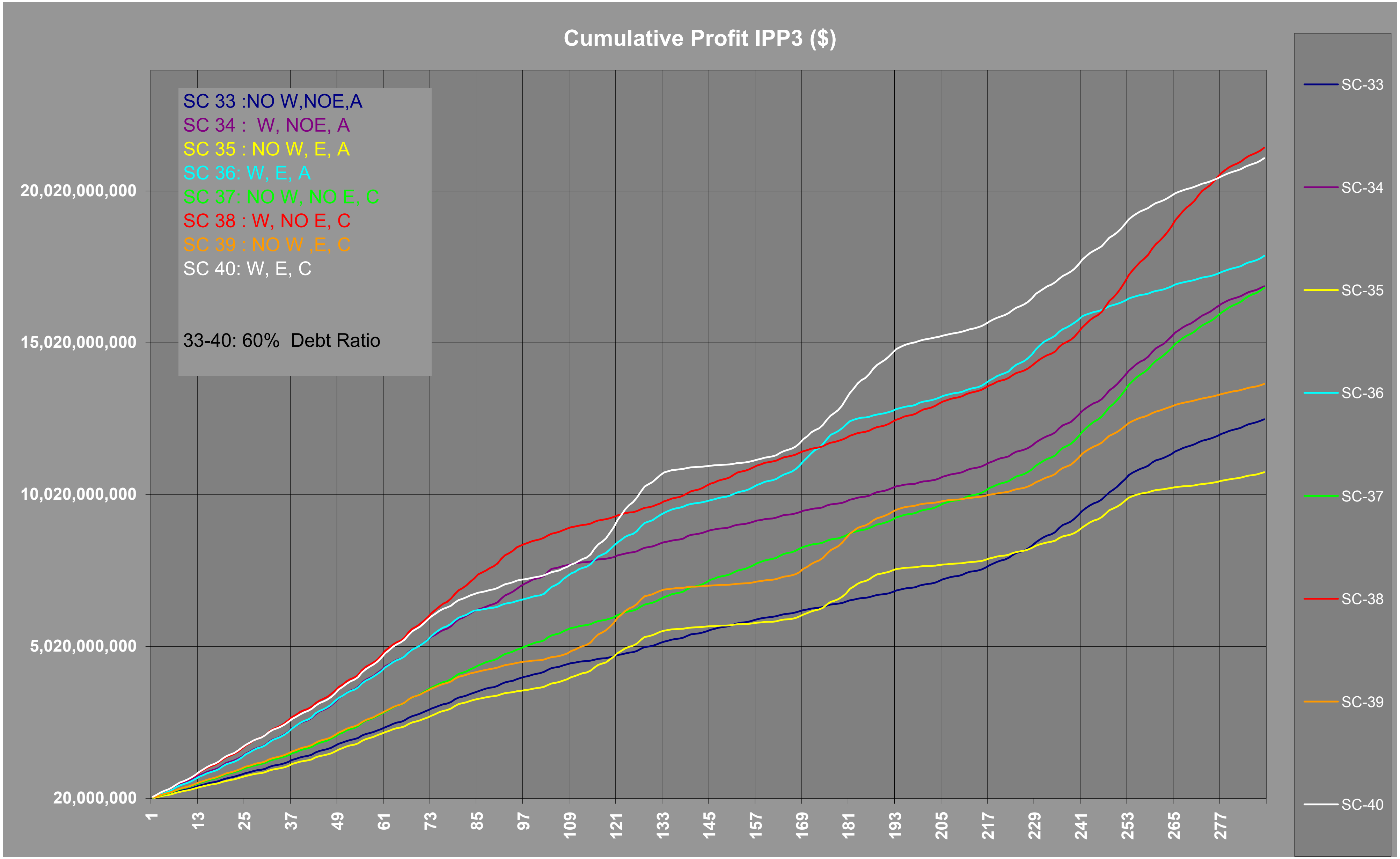
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



Cumulative Profit IPP3 ($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
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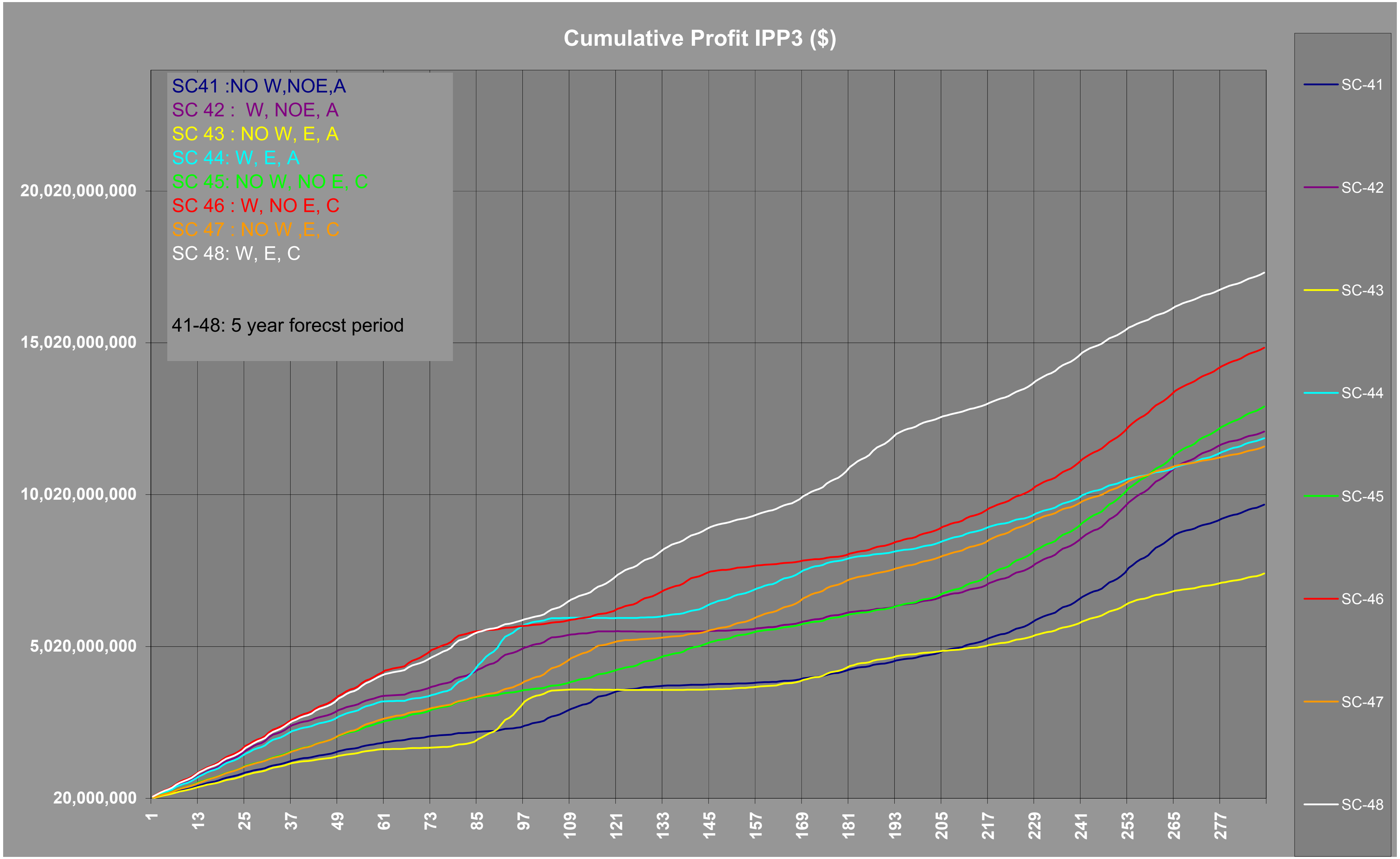
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



Cumulative Profit IPP3 ($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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253
265
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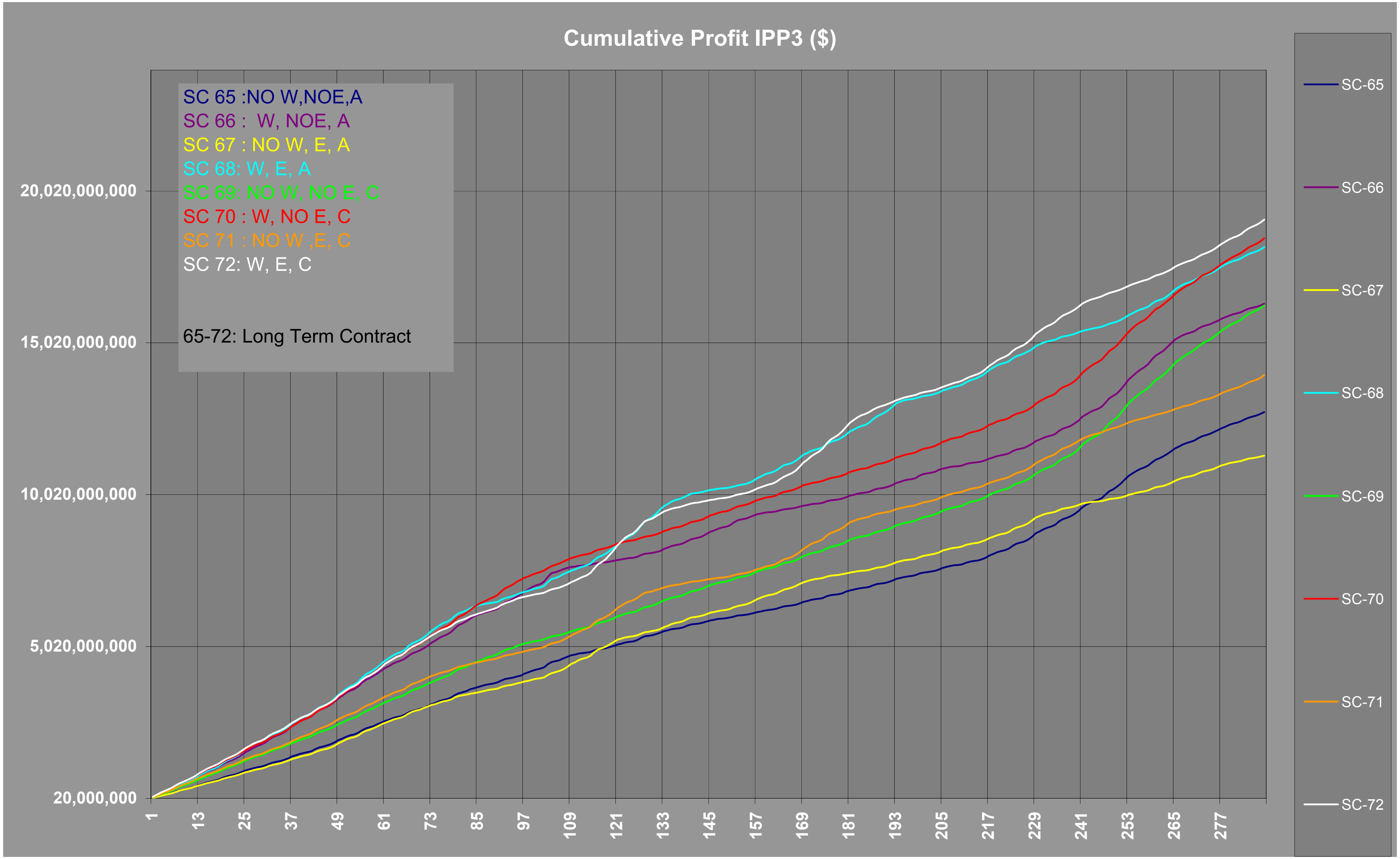
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



Cumulative Profit IPP3 ($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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253
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SC-66
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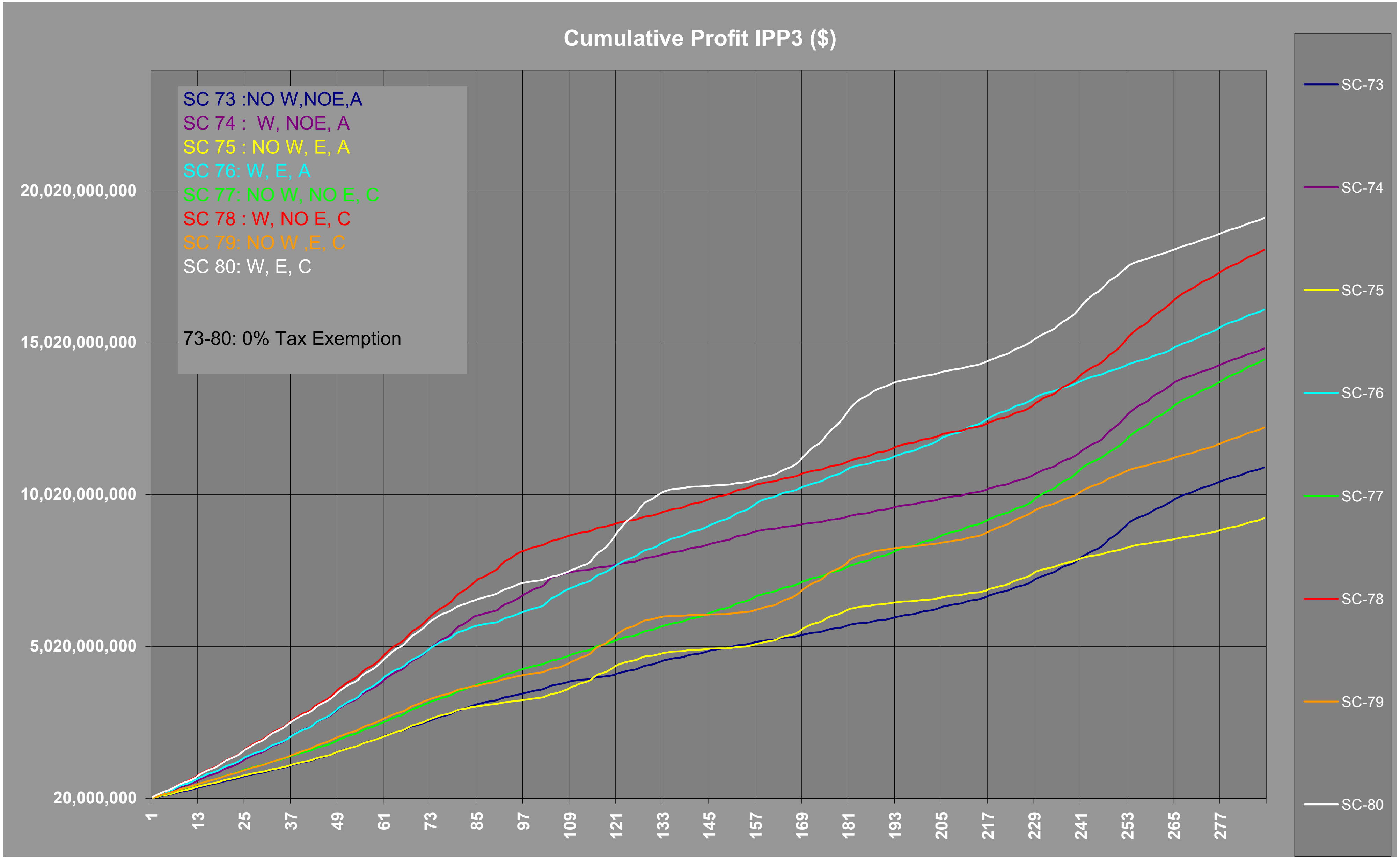
SC-70
SC-71
SC-72



Cumulative Profit IPP3 ($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
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253
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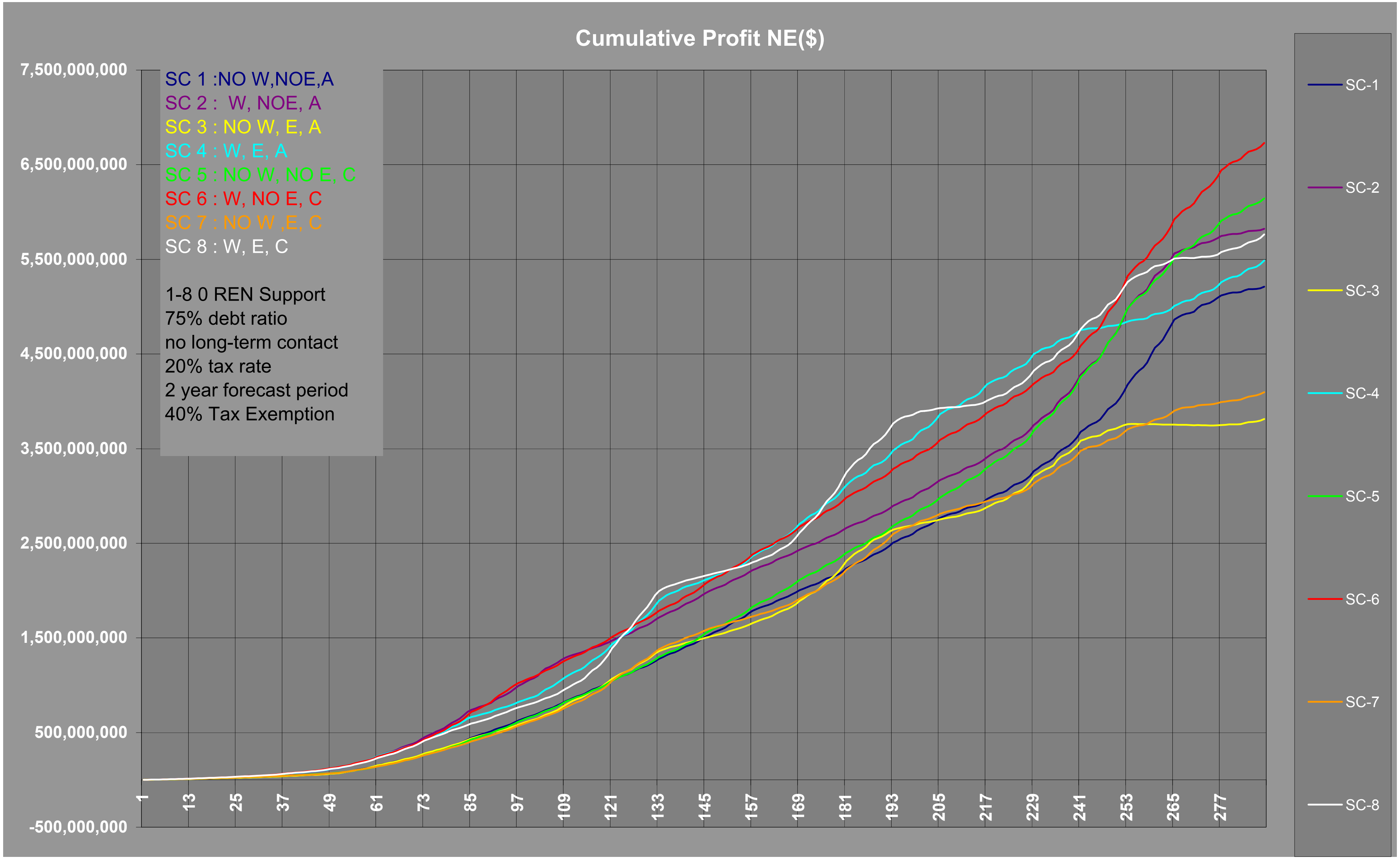
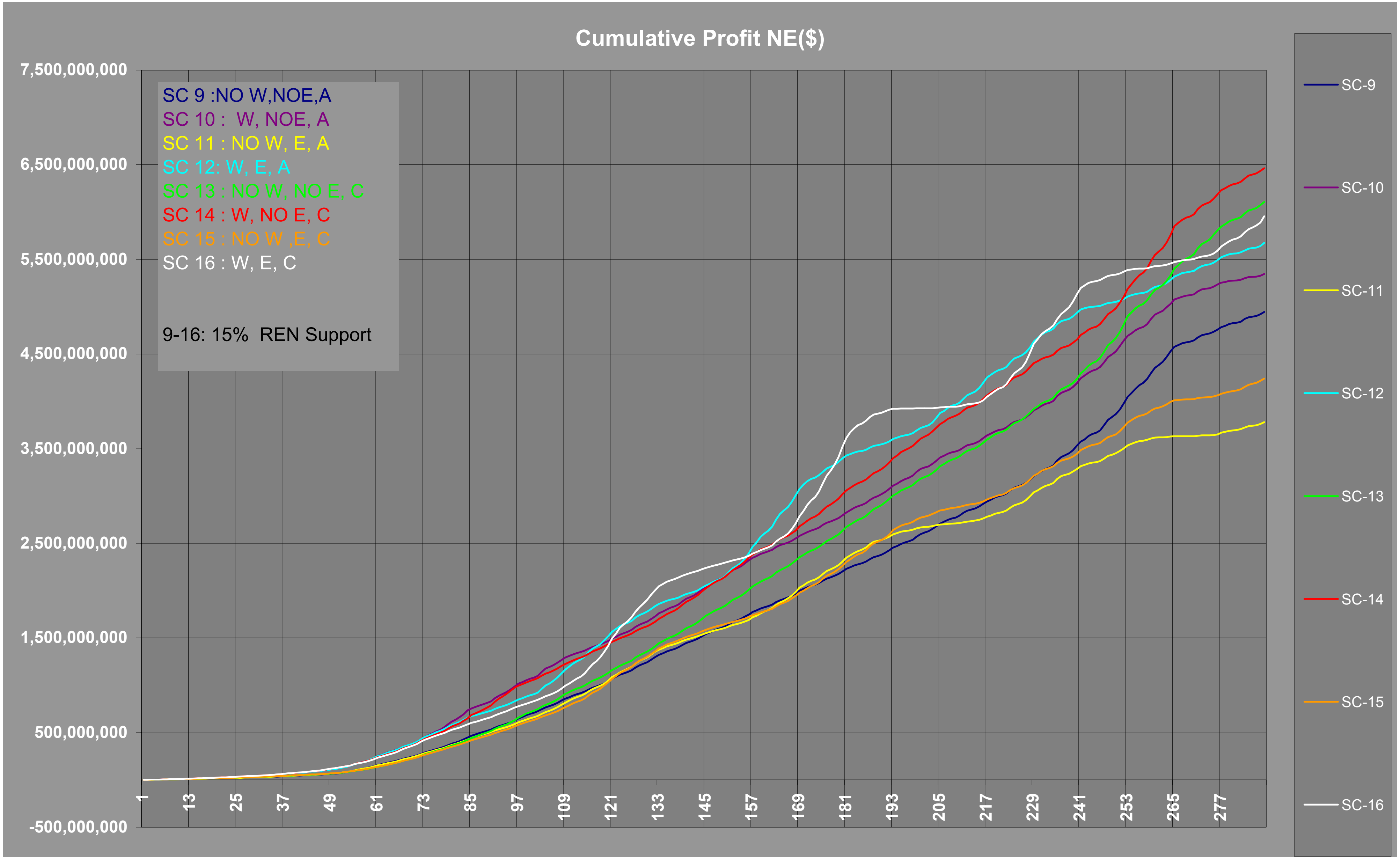
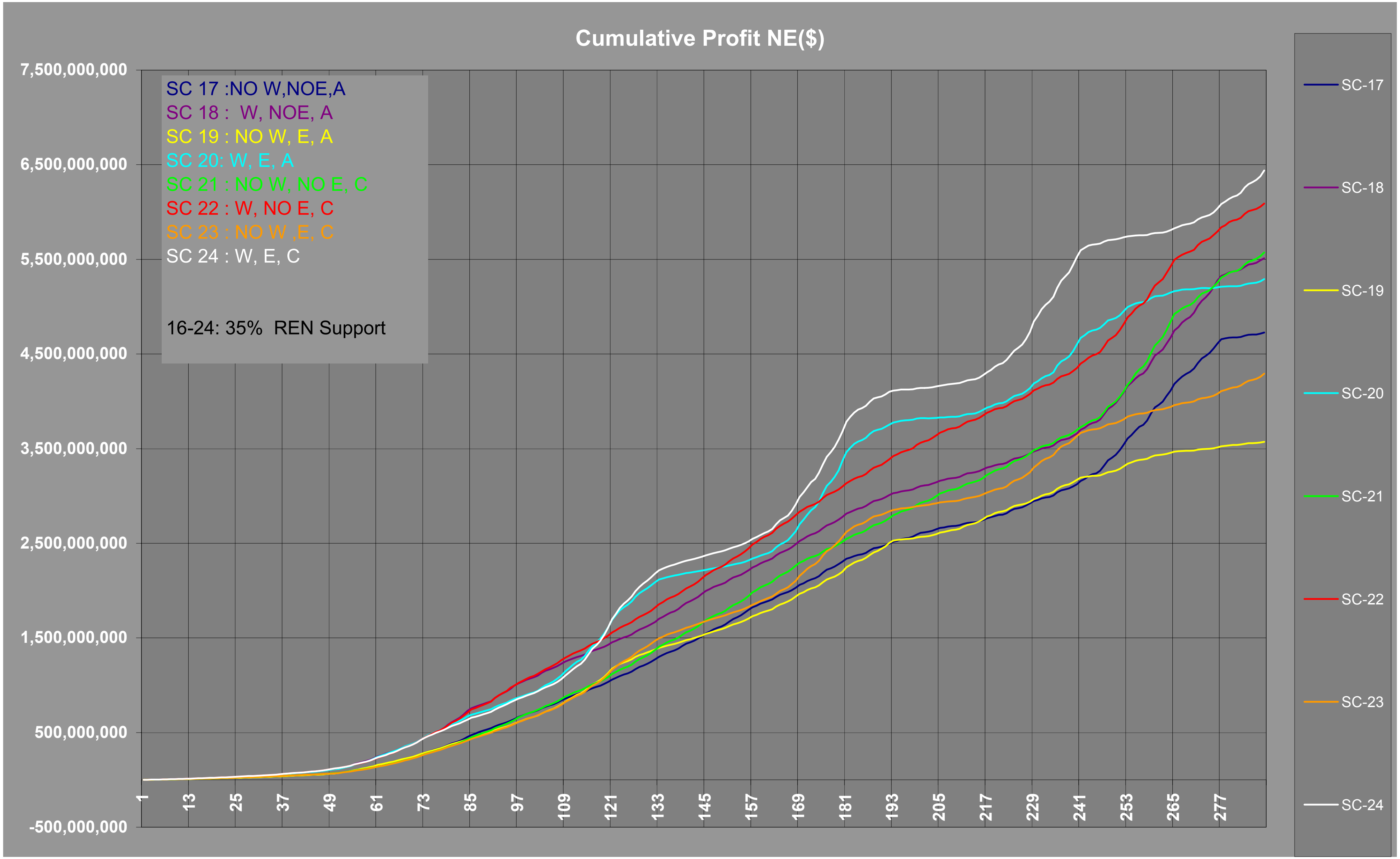
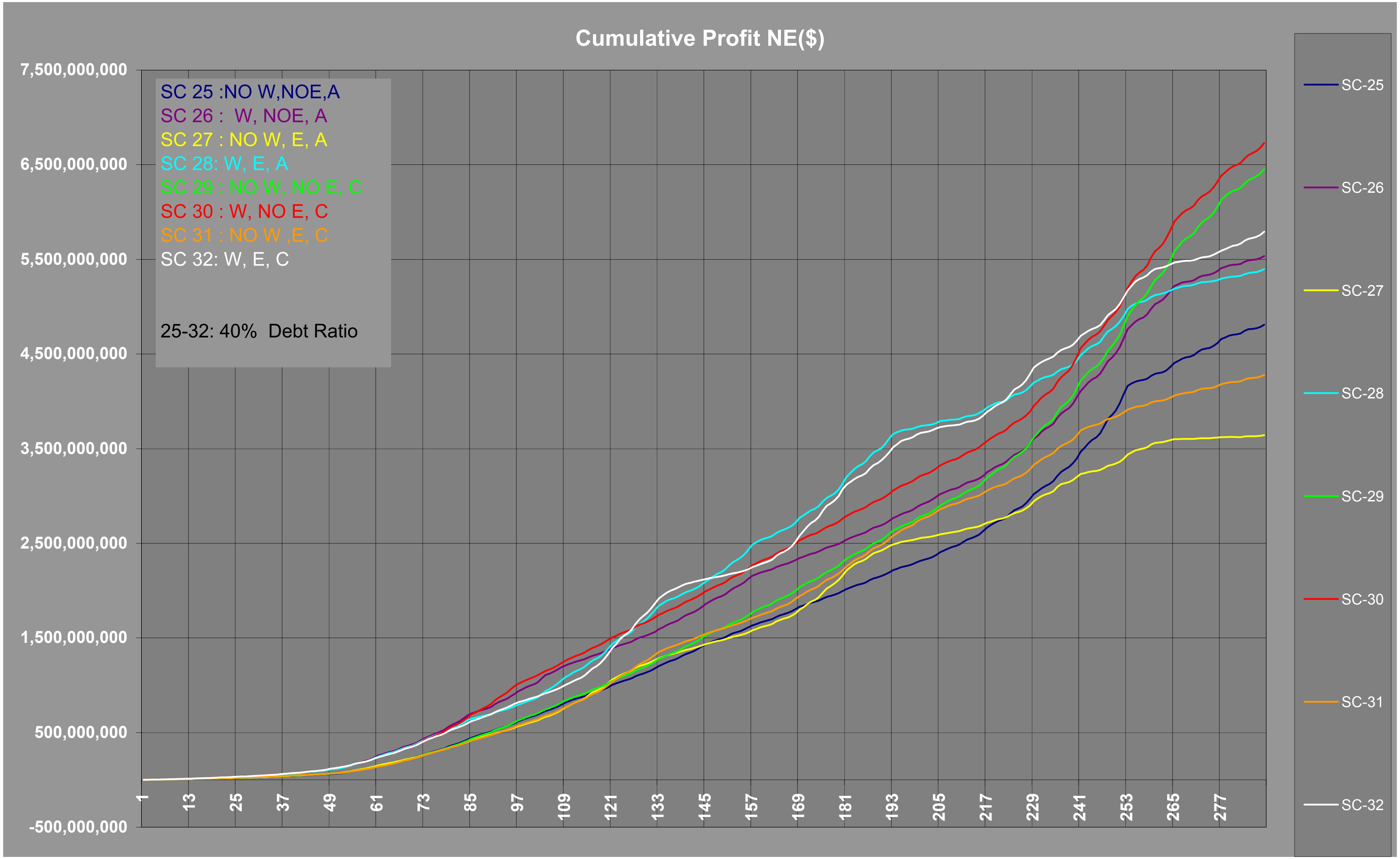
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80


Cumulative Profit NE($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
7,500,000,000
6,500,000,000
5,500,000,000
4,500,000,000
3,500,000,000
2,500,000,000
1,500,000,000
500,000,000
-500,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8


Cumulative Profit NE($)
7,500,000,000
6,500,000,000
5,500,000,000
4,500,000,000
3,500,000,000
2,500,000,000
1,500,000,000
500,000,000
-500,000,000
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



Cumulative Profit NE($)
7,500,000,000
6,500,000,000
5,500,000,000
4,500,000,000
3,500,000,000
2,500,000,000
1,500,000,000
500,000,000
-500,000,000
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
16-24: 35% REN Support
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24


Cumulative Profit NE($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
7,500,000,000
6,500,000,000
5,500,000,000
4,500,000,000
3,500,000,000
2,500,000,000
1,500,000,000
500,000,000
-500,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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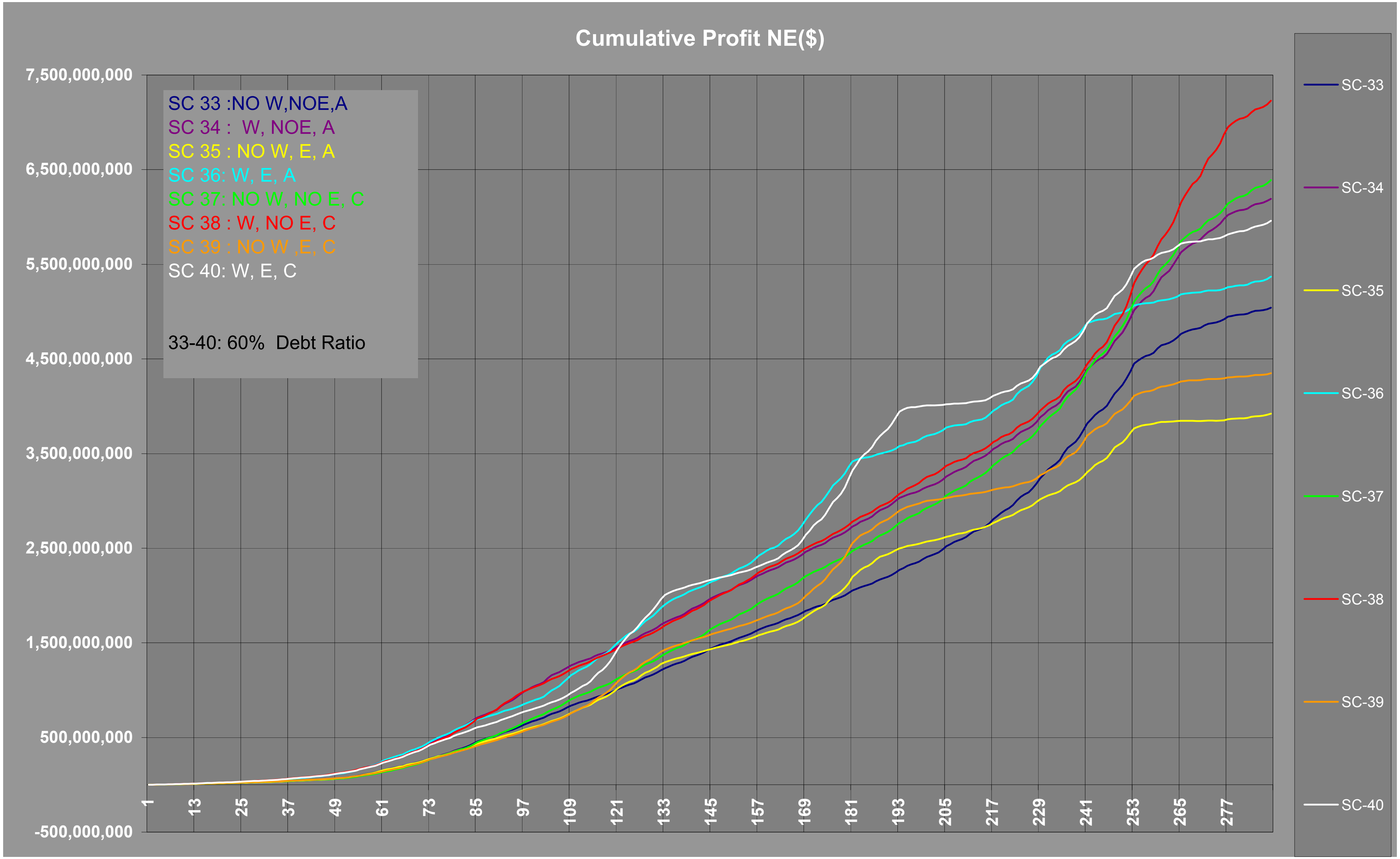
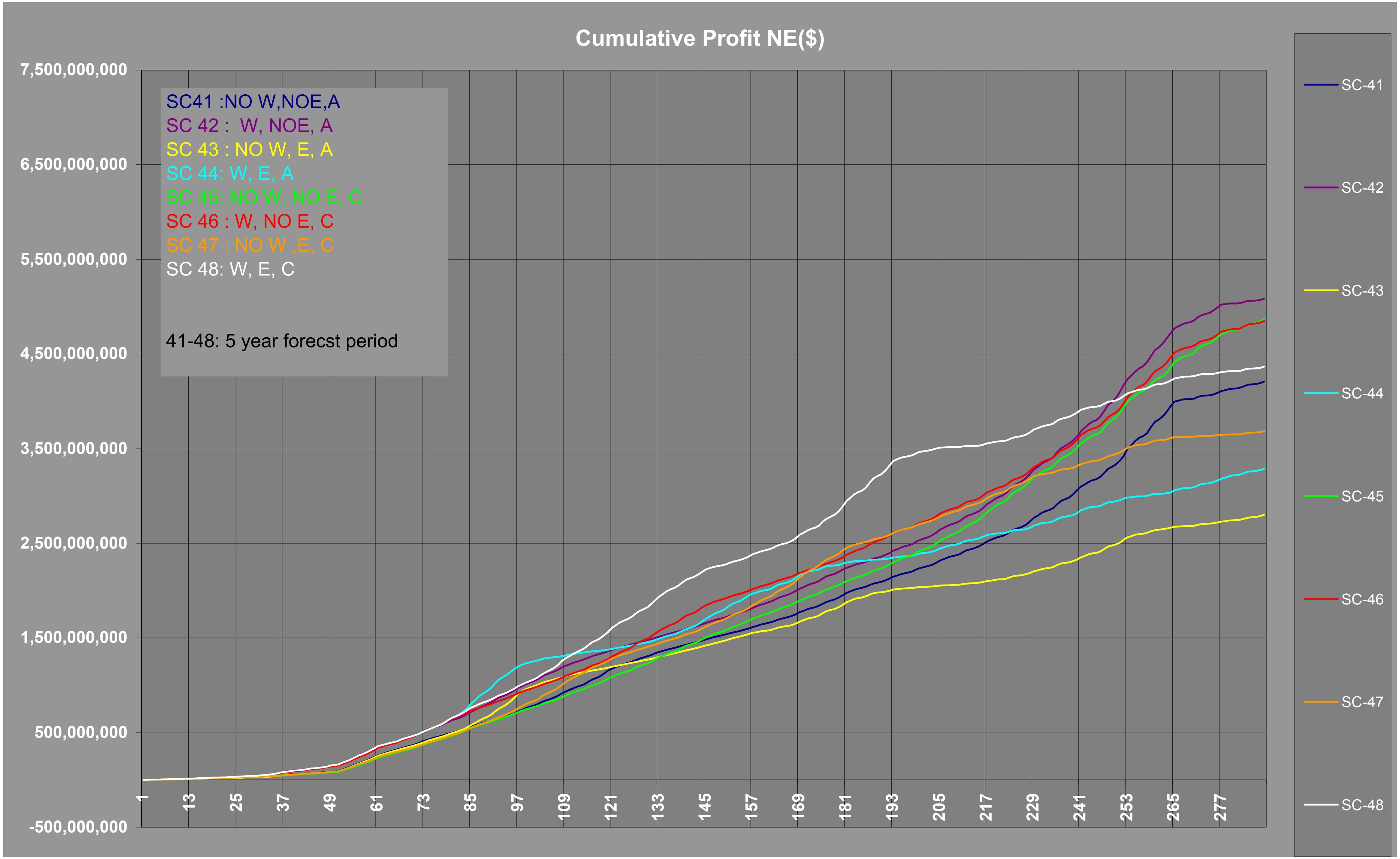
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



Cumulative Profit NE($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
7,500,000,000
6,500,000,000
5,500,000,000
4,500,000,000
3,500,000,000
2,500,000,000
1,500,000,000
500,000,000
-500,000,000
1 13 25 37 49 61 73 85 97 109 121 133 145 157 169 181 193 205 217 229 241 253 265 277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



Cumulative Profit NE($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
7,500,000,000
6,500,000,000
5,500,000,000
4,500,000,000
3,500,000,000
2,500,000,000
1,500,000,000
500,000,000
-500,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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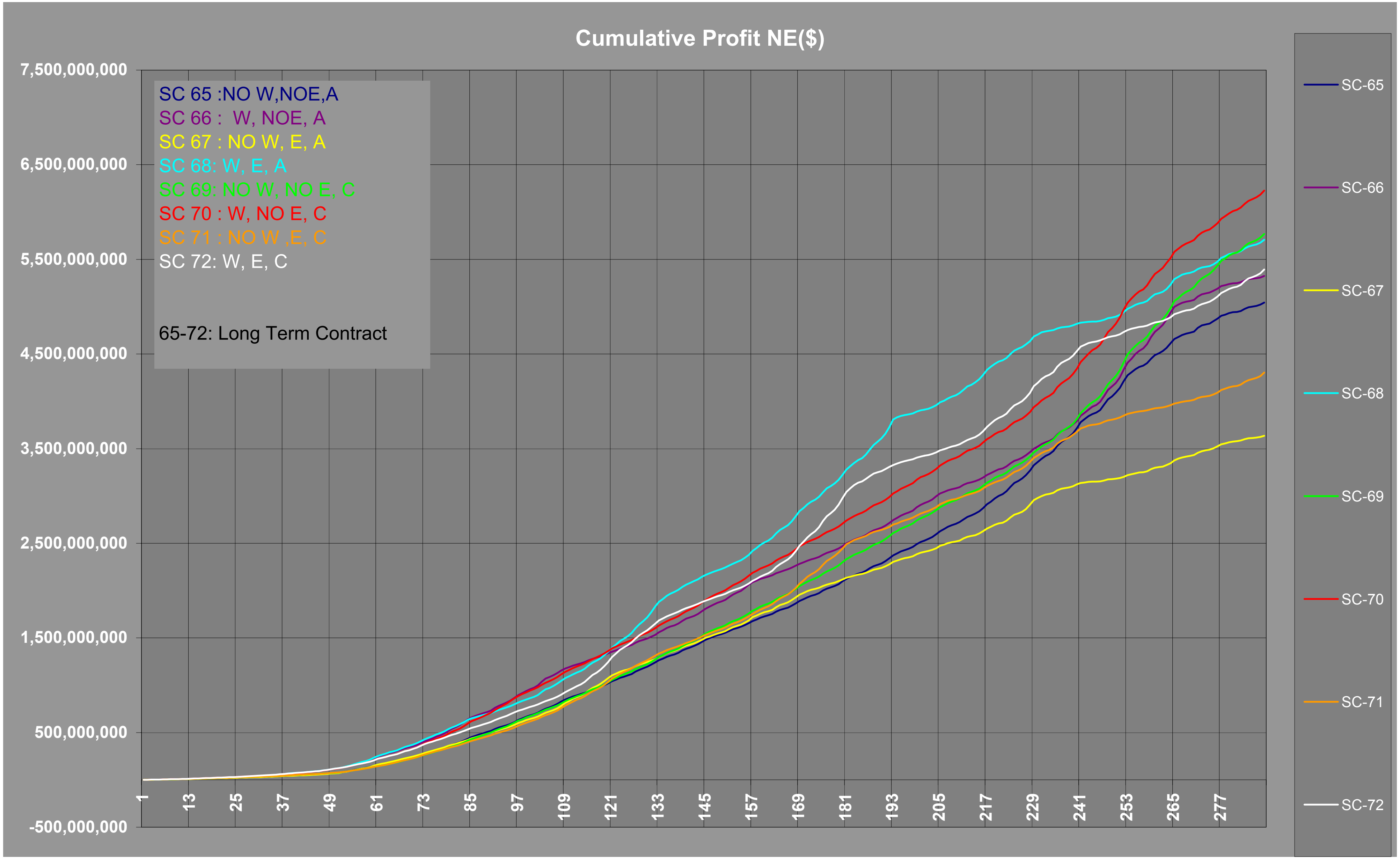
SC-46
SC-47
SC-48


Cumulative Profit NE($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
7,500,000,000
6,500,000,000
5,500,000,000
4,500,000,000
3,500,000,000
2,500,000,000
1,500,000,000
500,000,000
-500,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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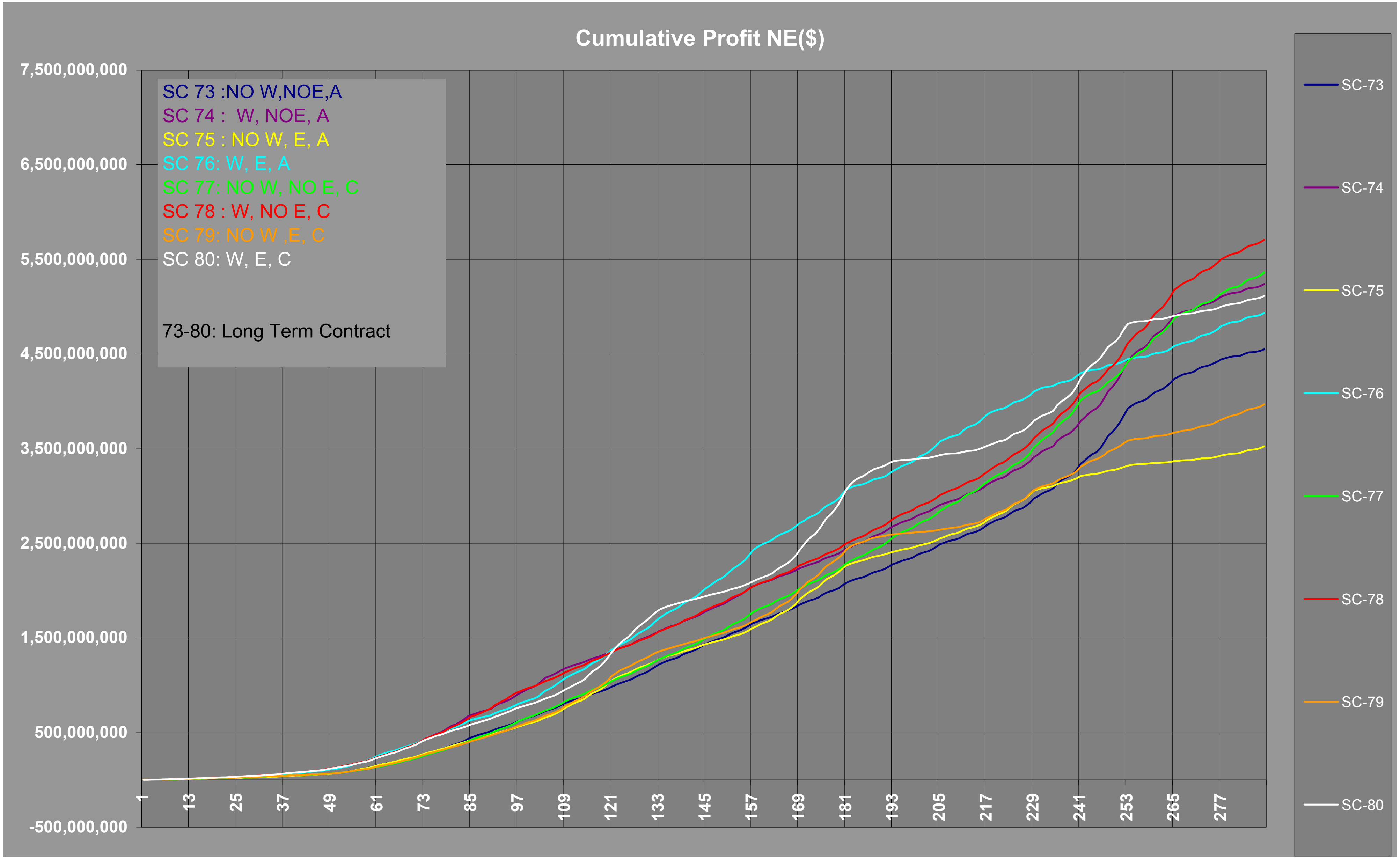
SC-70
SC-71
SC-72


Cumulative Profit NE($)
7,500,000,000
6,500,000,000
5,500,000,000
4,500,000,000
3,500,000,000
2,500,000,000
1,500,000,000
500,000,000
-500,000,000
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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SC-73
SC-74
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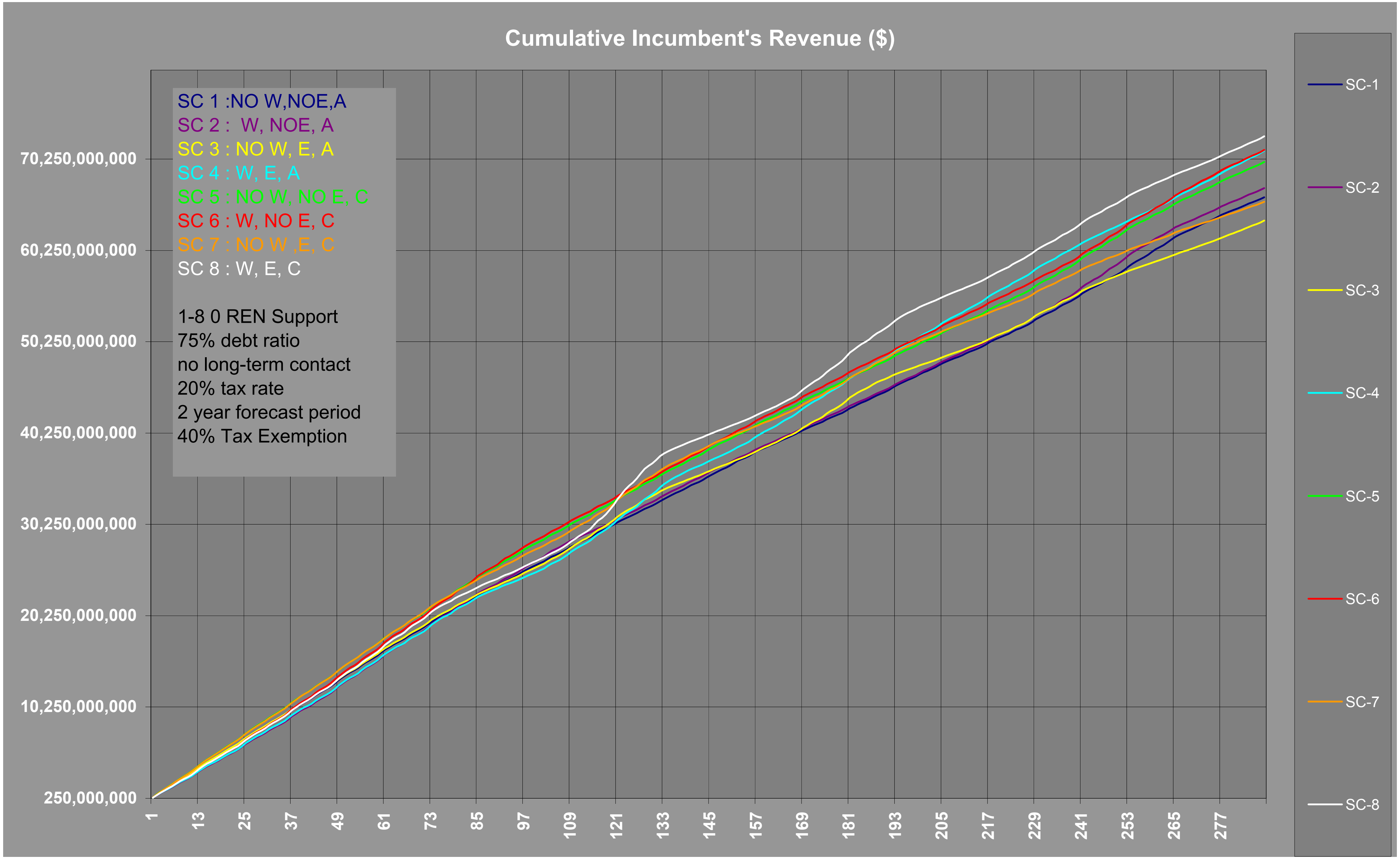
SC-78
SC-79
SC-80



Cumulative Incumbent's Revenue ($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
70,250,000,000
60,250,000,000
50,250,000,000
40,250,000,000
30,250,000,000
20,250,000,000
10,250,000,000
250,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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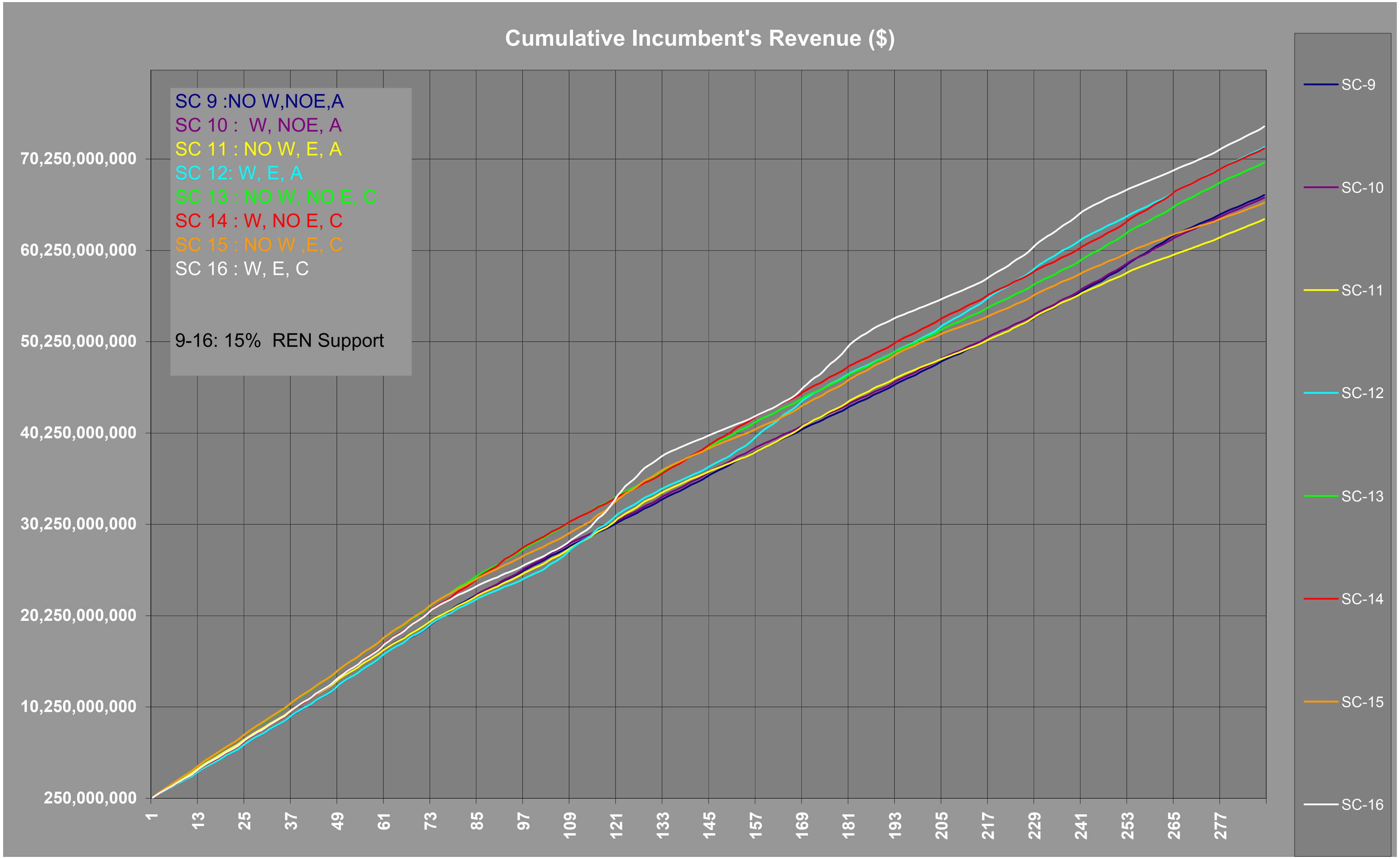
SC-6
SC-7
SC-8



Cumulative Incumbent's Revenue ($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
70,250,000,000
60,250,000,000
50,250,000,000
40,250,000,000
30,250,000,000
20,250,000,000
10,250,000,000
250,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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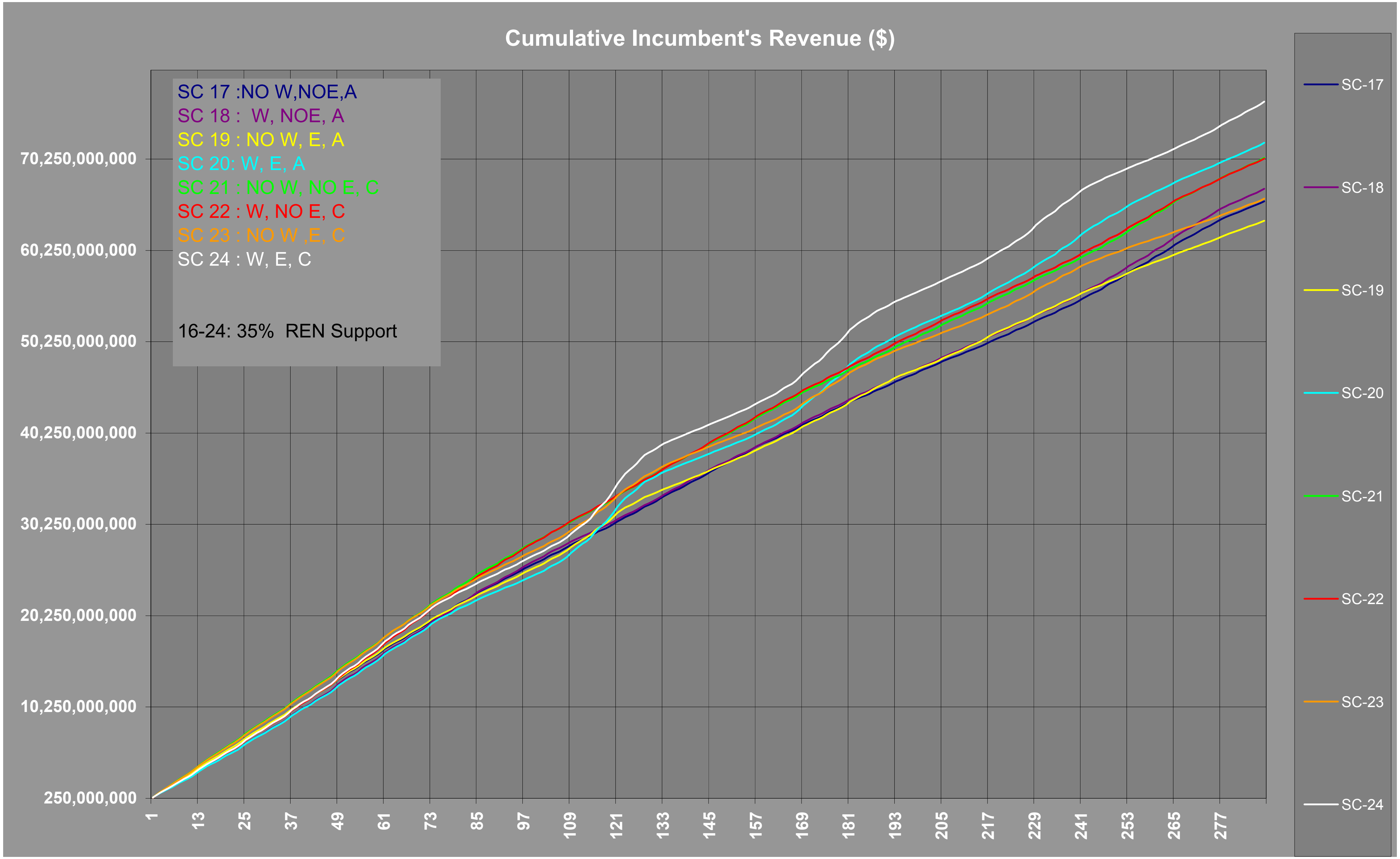
SC-14
SC-15
SC-16


Cumulative Incumbent's Revenue ($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
16-24: 35% REN Support
70,250,000,000
60,250,000,000
50,250,000,000
40,250,000,000
30,250,000,000
20,250,000,000
10,250,000,000
250,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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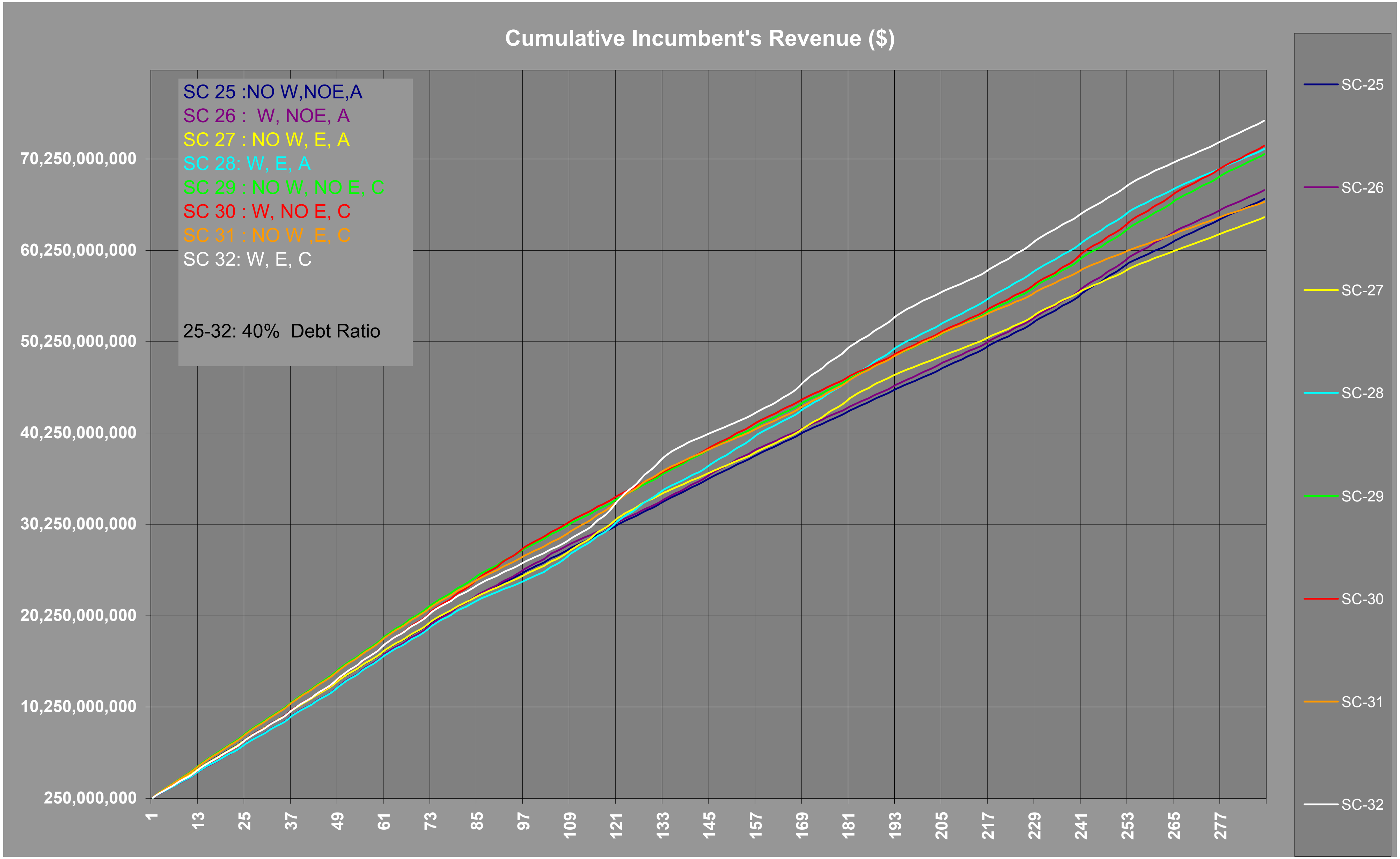
SC-22
SC-23
SC-24


Cumulative Incumbent's Revenue ($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
70,250,000,000
60,250,000,000
50,250,000,000
40,250,000,000
30,250,000,000
20,250,000,000
10,250,000,000
250,000,000
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SC-25
SC-26
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SC-28
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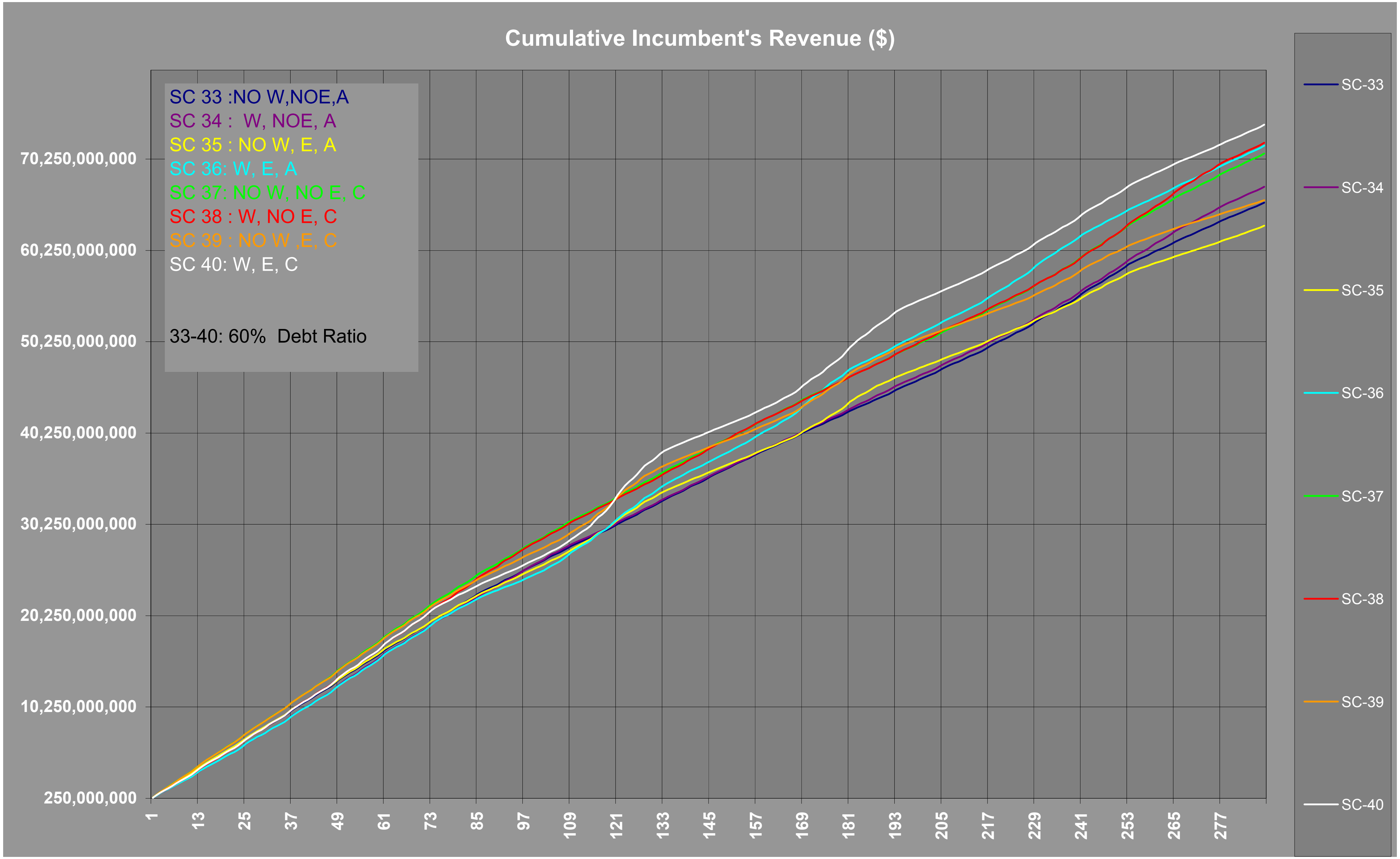
SC-30
SC-31
SC-32



Cumulative Incumbent's Revenue ($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
70,250,000,000
60,250,000,000
50,250,000,000
40,250,000,000
30,250,000,000
20,250,000,000
10,250,000,000
250,000,000
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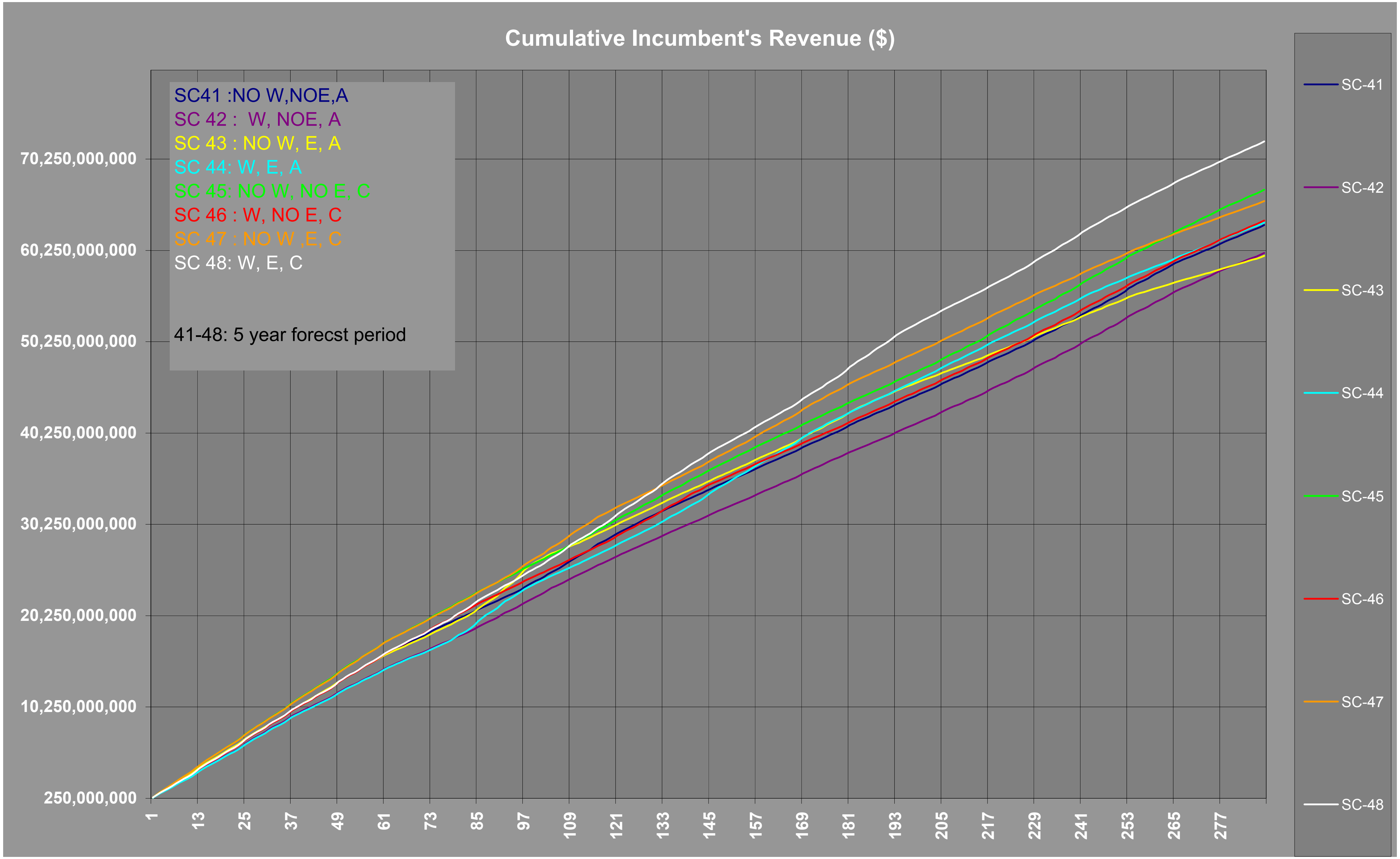
SC-40


Cumulative Incumbent's Revenue ($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
70,250,000,000
60,250,000,000
50,250,000,000
40,250,000,000
30,250,000,000
20,250,000,000
10,250,000,000
250,000,000
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73
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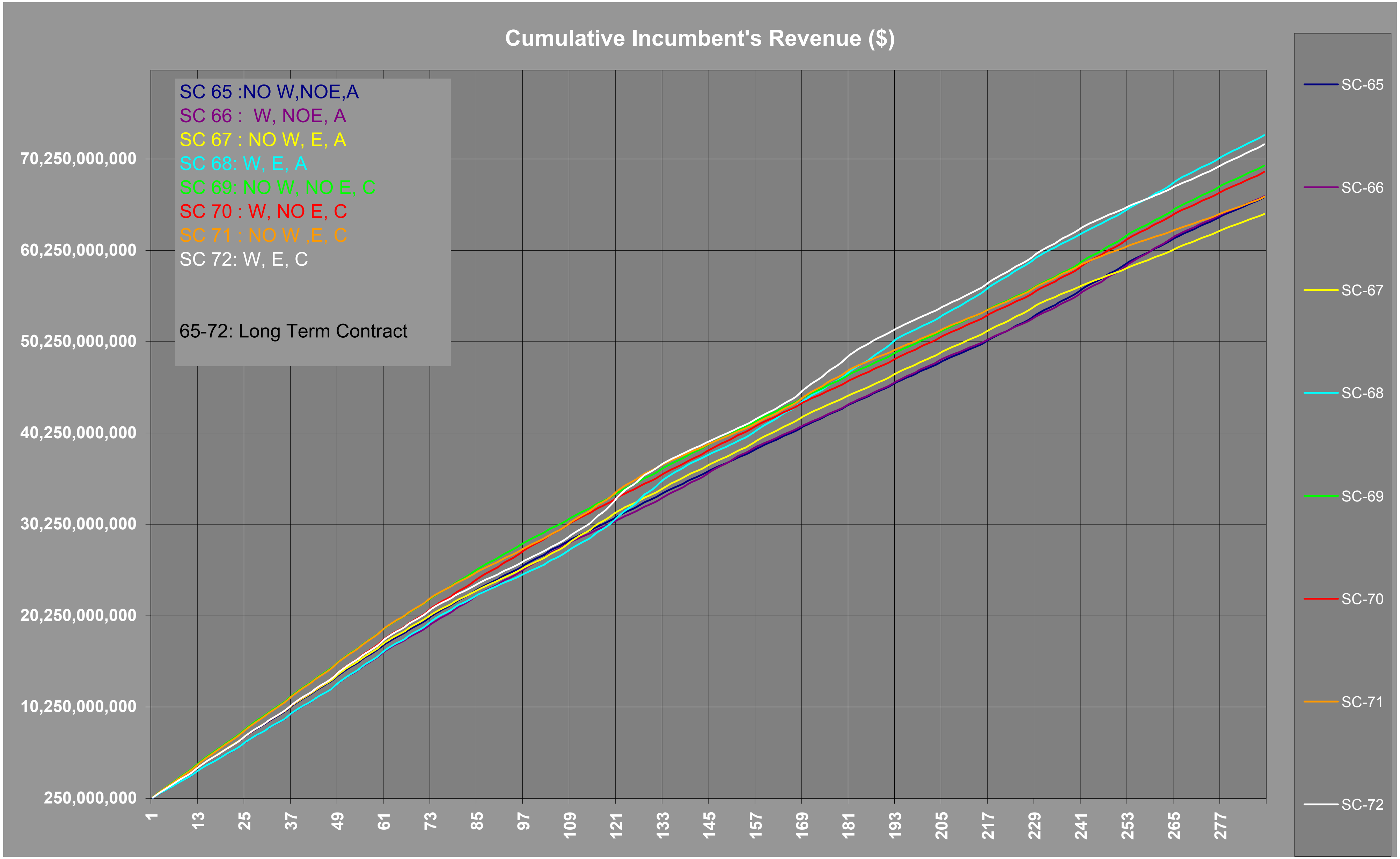
SC-48



Cumulative Incumbent's Revenue ($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
70,250,000,000
60,250,000,000
50,250,000,000
40,250,000,000
30,250,000,000
20,250,000,000
10,250,000,000
250,000,000
1
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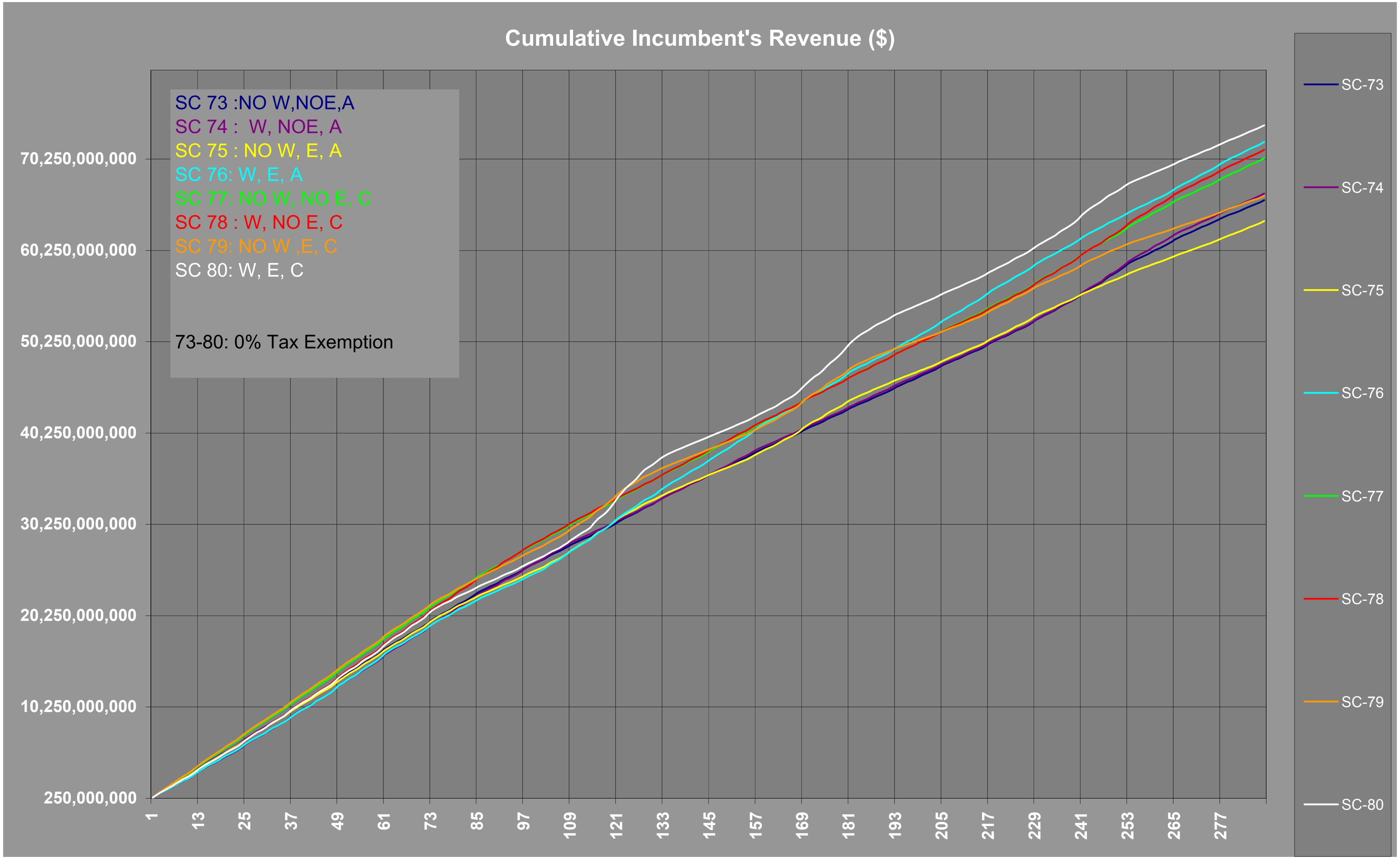
SC-72


Cumulative Incumbent's Revenue ($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
70,250,000,000
60,250,000,000
50,250,000,000
40,250,000,000
30,250,000,000
20,250,000,000
10,250,000,000
250,000,000
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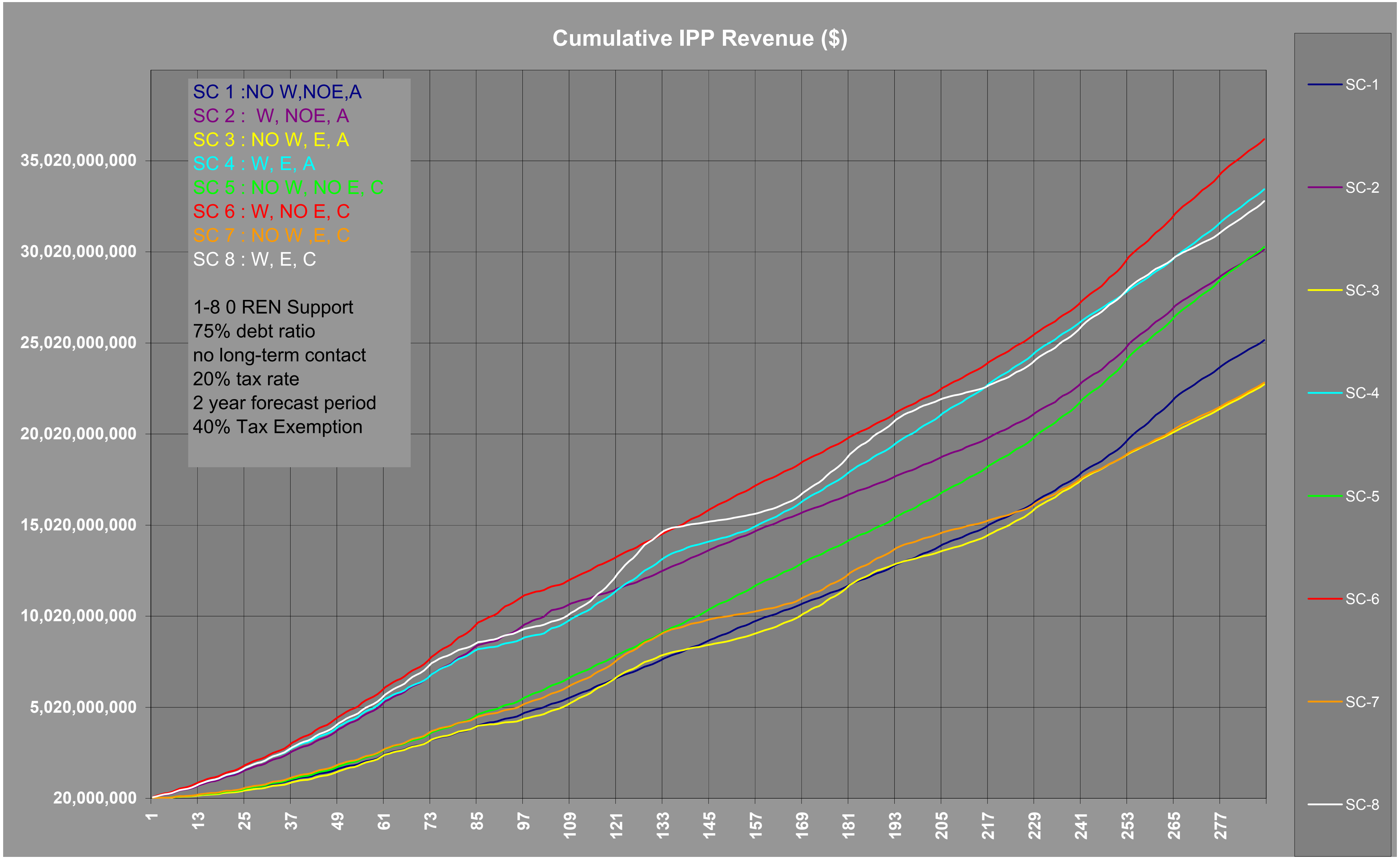

Cumulative IPP Revenue ($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
35,020,000,000
30,020,000,000
25,020,000,000
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
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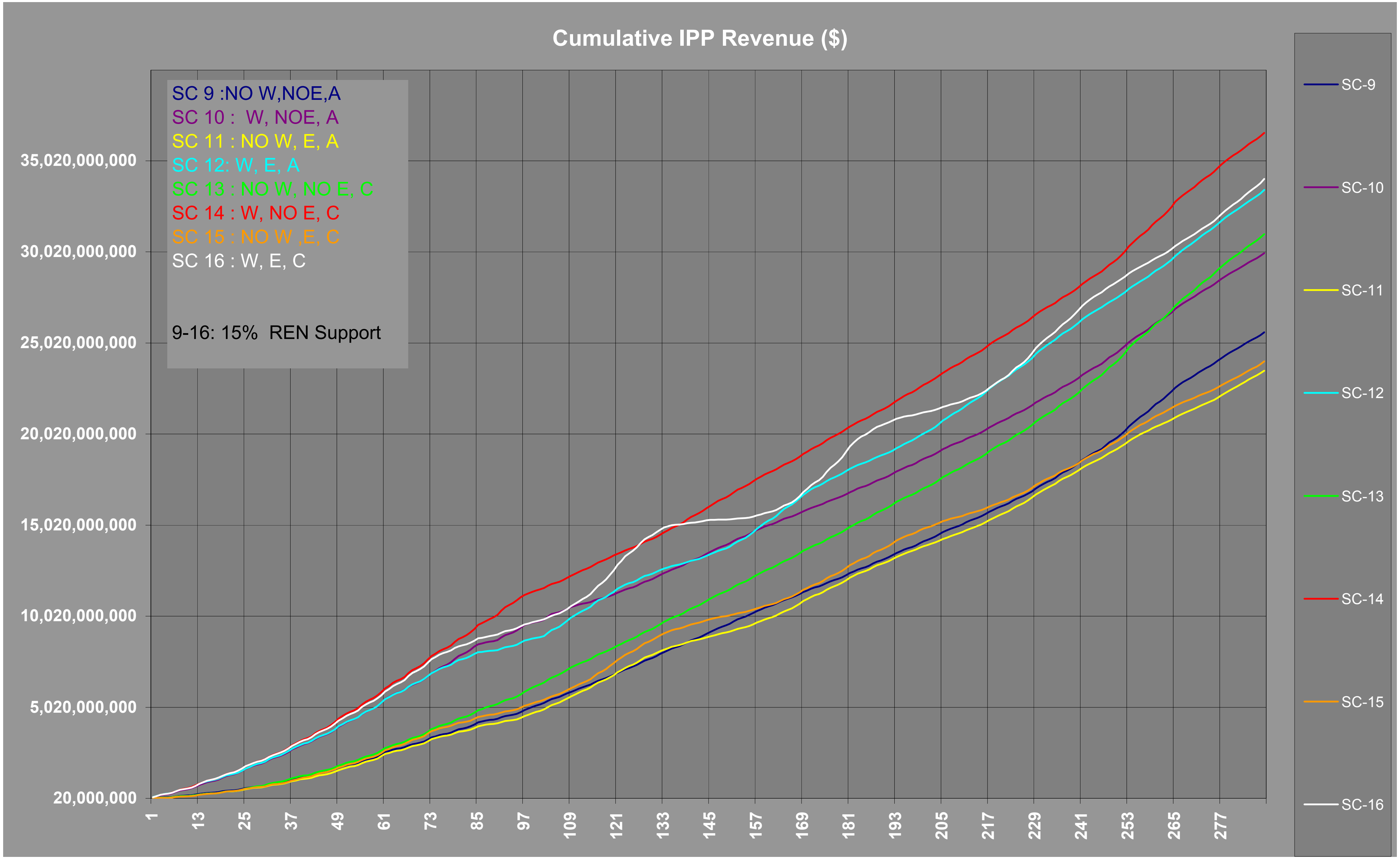

Cumulative IPP Revenue ($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
35,020,000,000
30,020,000,000
25,020,000,000
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
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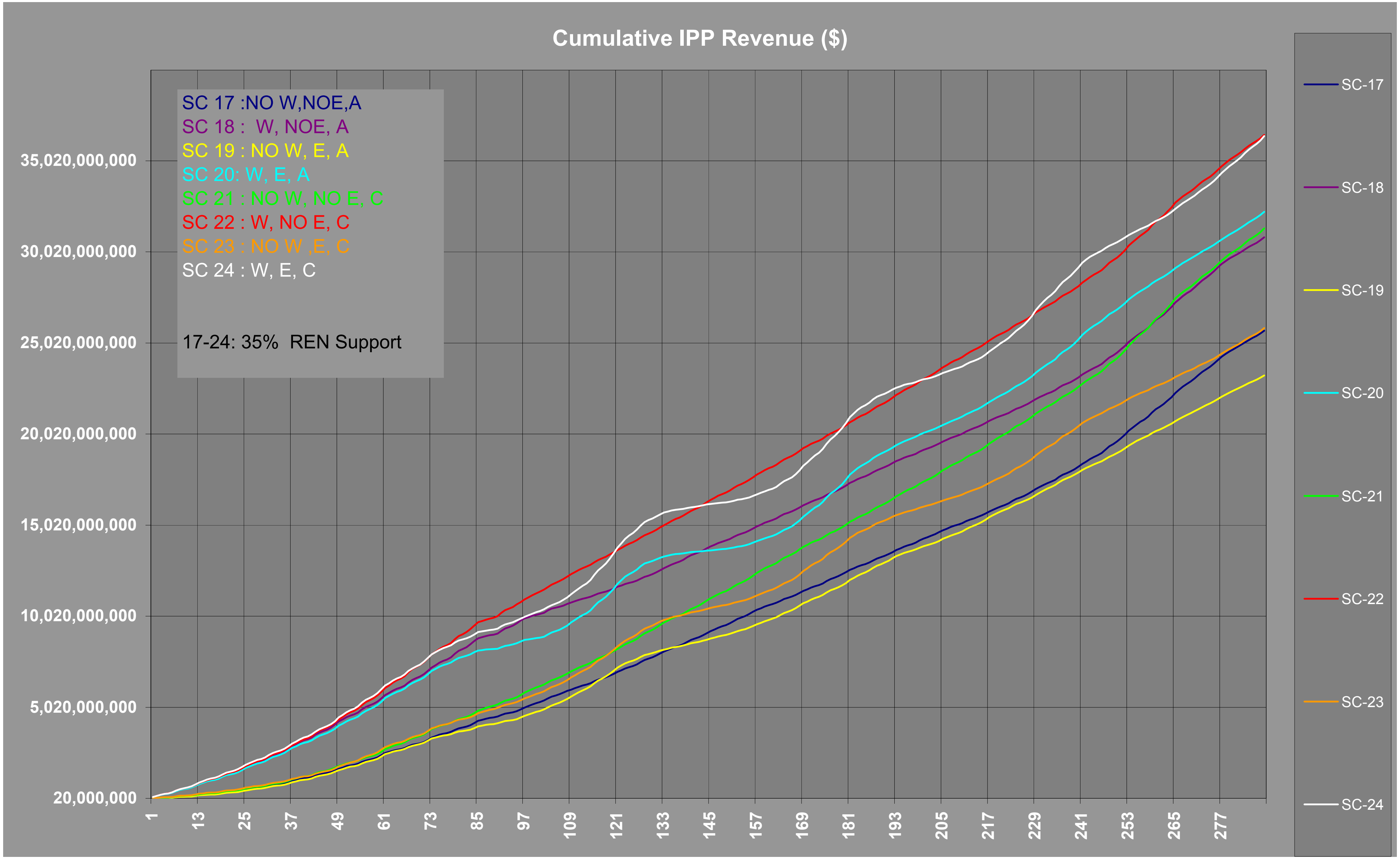
SC-16



Cumulative IPP Revenue ($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
35,020,000,000
30,020,000,000
25,020,000,000
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
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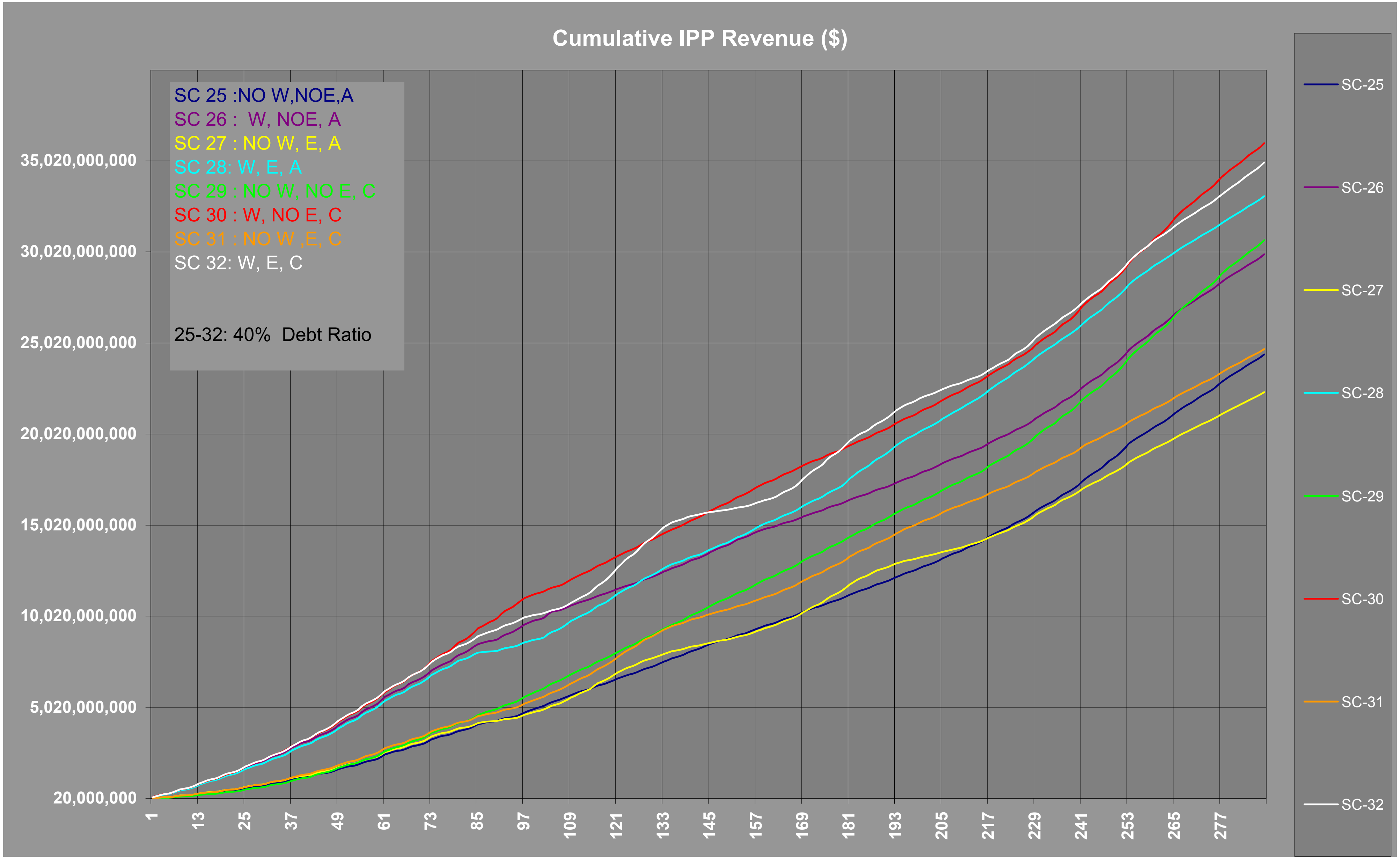
Cumulative IPP Revenue ($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
35,020,000,000
30,020,000,000
25,020,000,000
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
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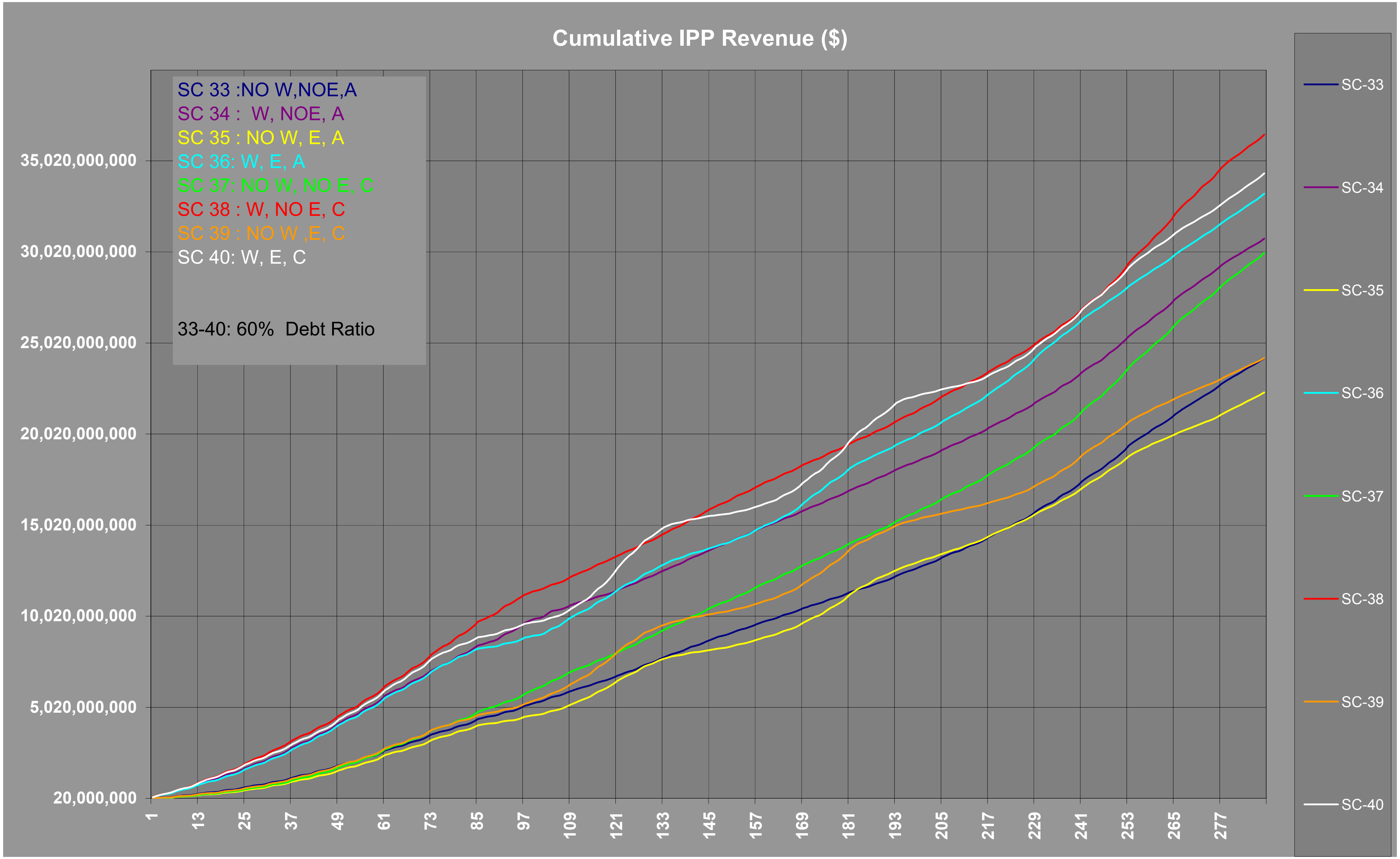
SC-32



Cumulative IPP Revenue ($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
35,020,000,000
30,020,000,000
25,020,000,000
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
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SC-38
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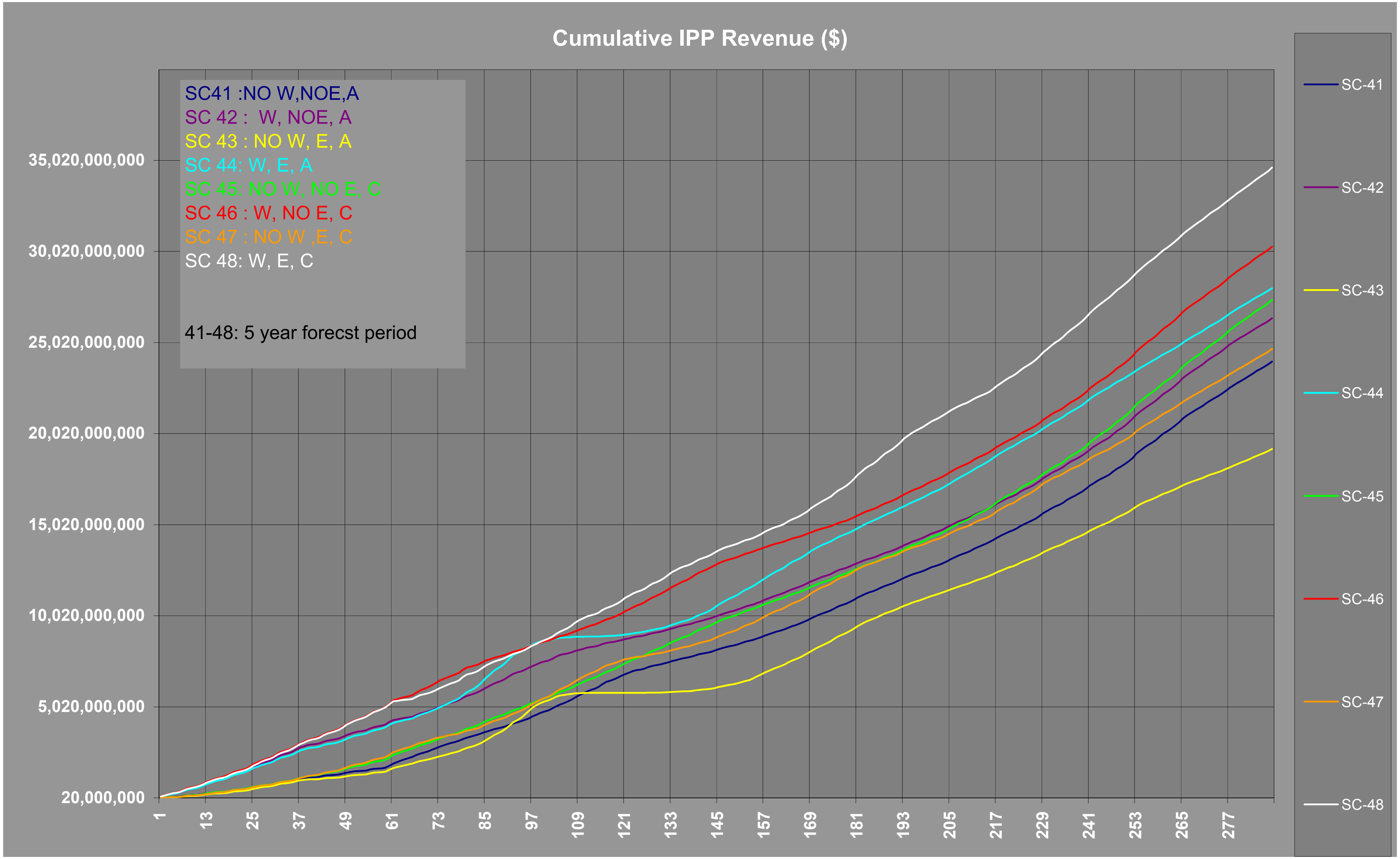
SC-40


Cumulative IPP Revenue ($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
35,020,000,000
30,020,000,000
25,020,000,000
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
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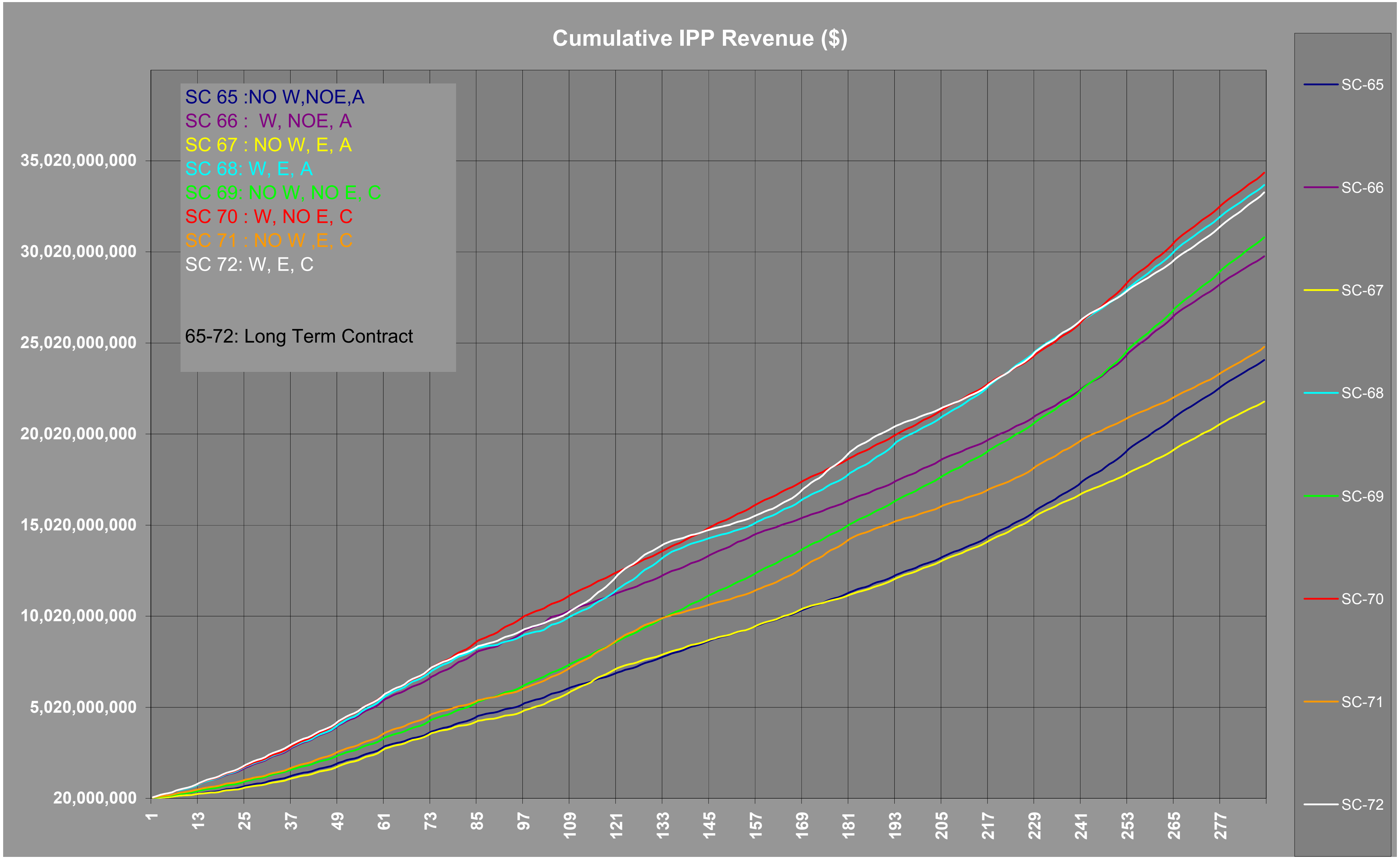
SC-48



Cumulative IPP Revenue ($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
35,020,000,000
30,020,000,000
25,020,000,000
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
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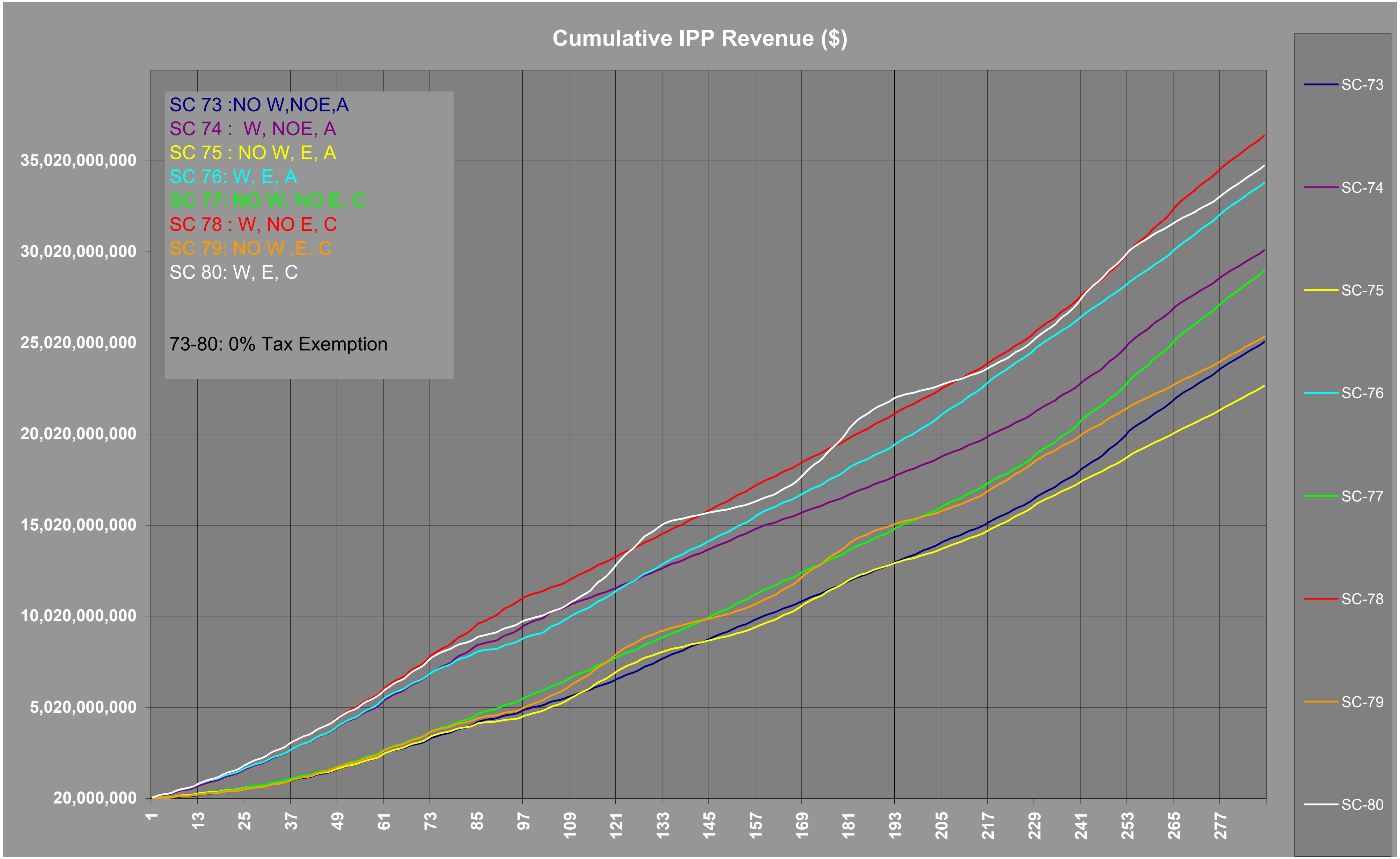
SC-72



Cumulative IPP Revenue ($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
35,020,000,000
30,020,000,000
25,020,000,000
20,020,000,000
15,020,000,000
10,020,000,000
5,020,000,000
20,000,000
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SC-73
SC-74
SC-75
SC-76
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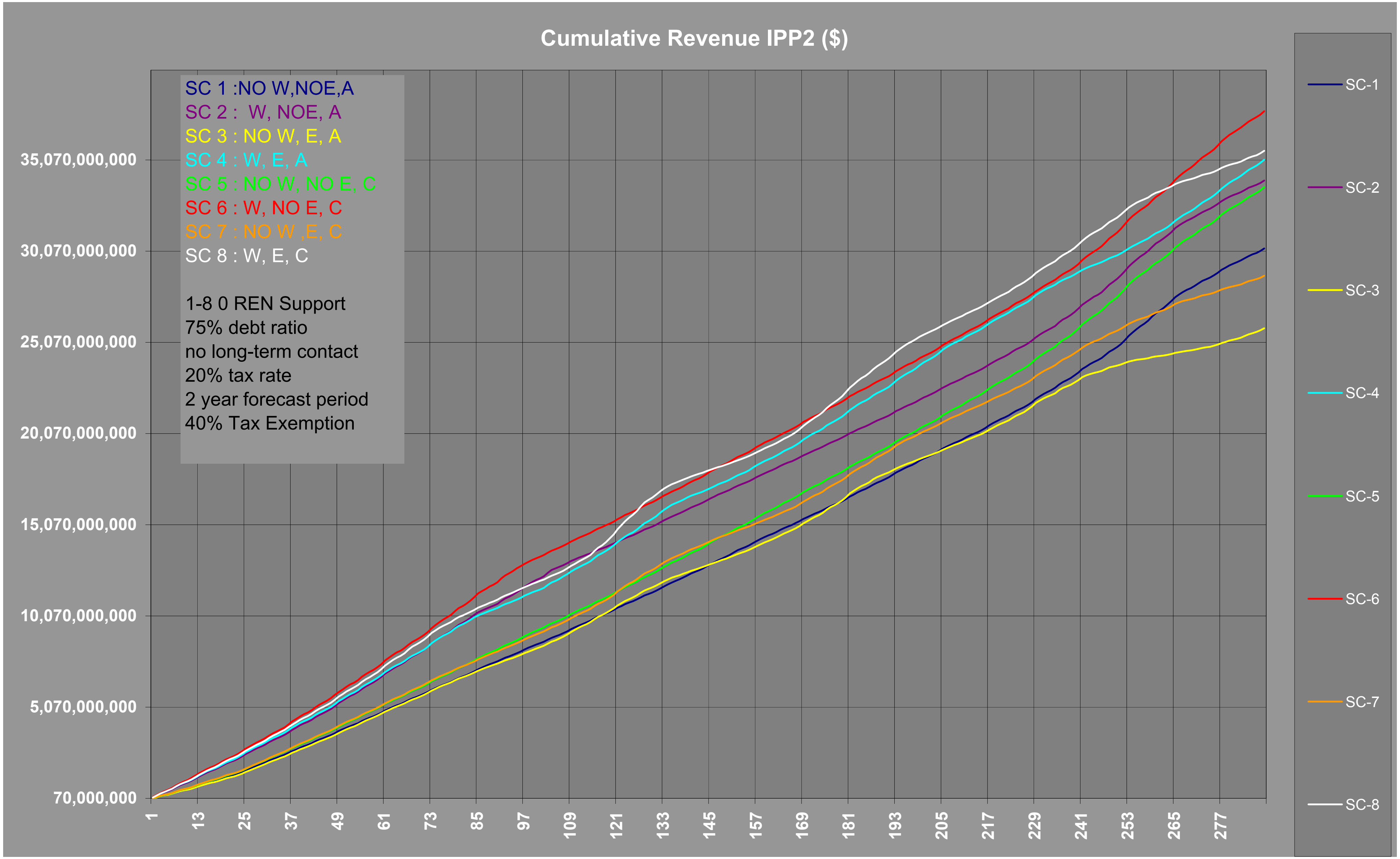
SC-78
SC-79
SC-80



Cumulative Revenue IPP2 ($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
35,070,000,000
30,070,000,000
25,070,000,000
20,070,000,000
15,070,000,000
10,070,000,000
5,070,000,000
70,000,000
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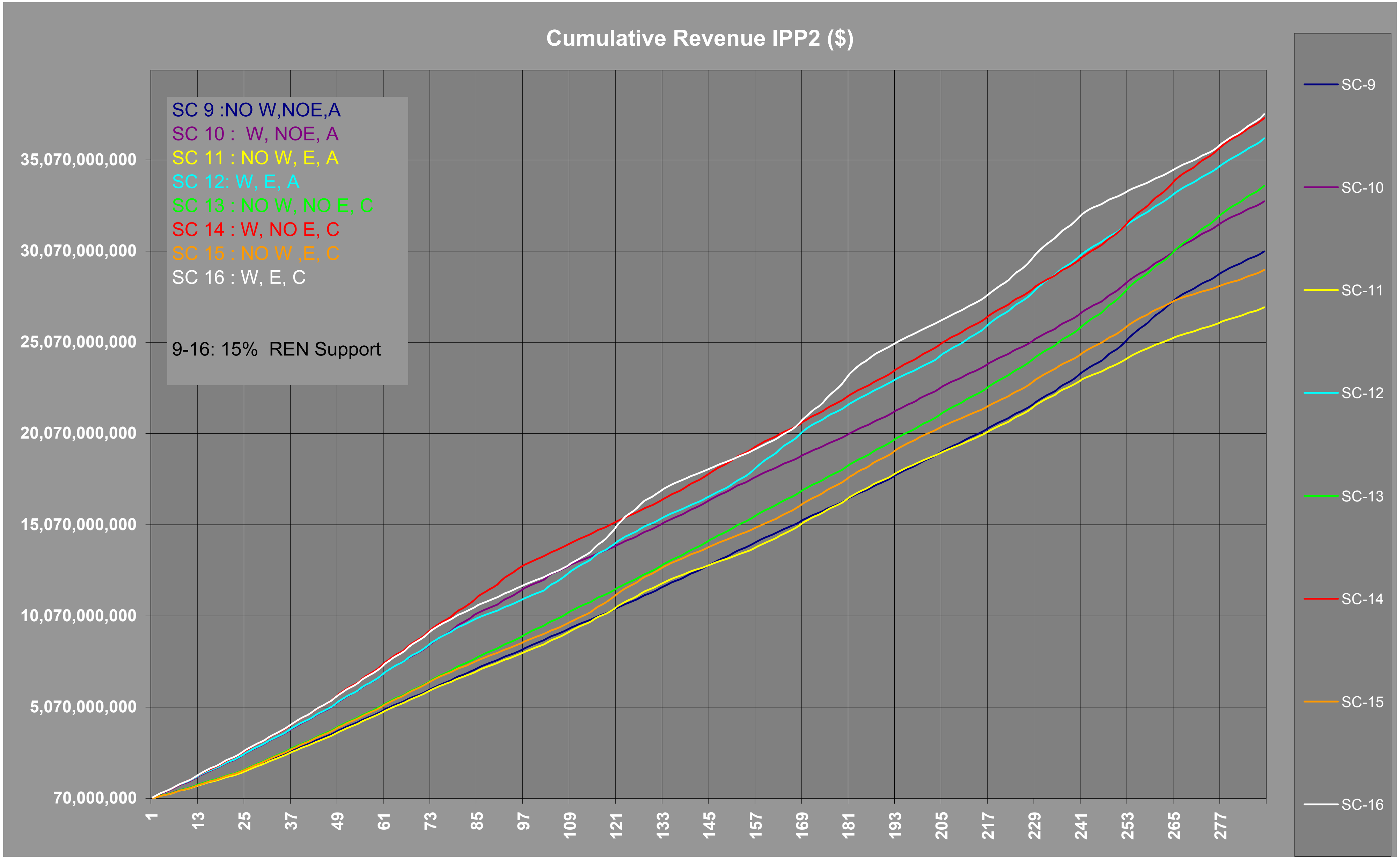
Cumulative Revenue IPP2 ($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
35,070,000,000
30,070,000,000
25,070,000,000
20,070,000,000
15,070,000,000
10,070,000,000
5,070,000,000
70,000,000
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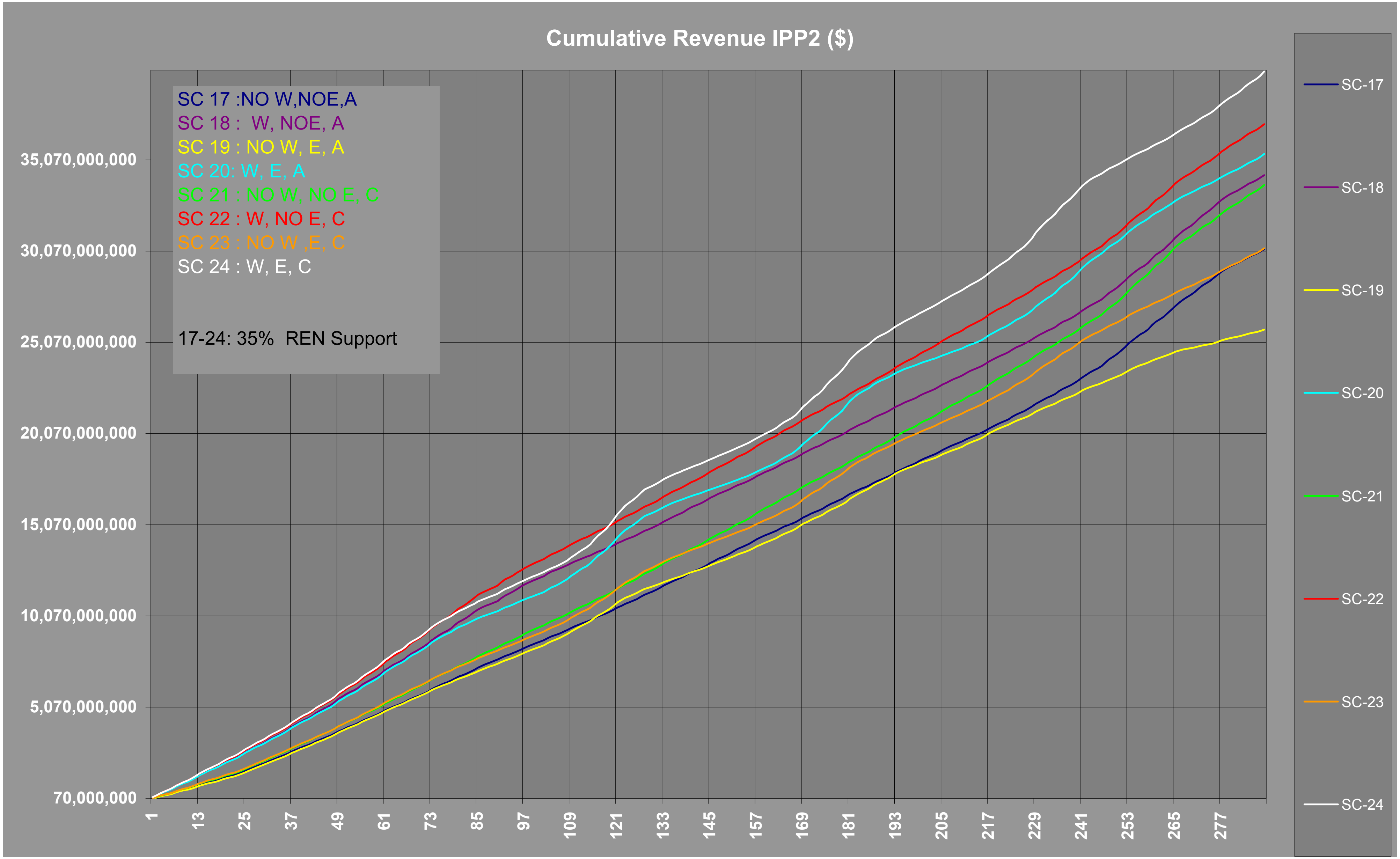
SC-16



Cumulative Revenue IPP2 ($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
35,070,000,000
30,070,000,000
25,070,000,000
20,070,000,000
15,070,000,000
10,070,000,000
5,070,000,000
70,000,000
1
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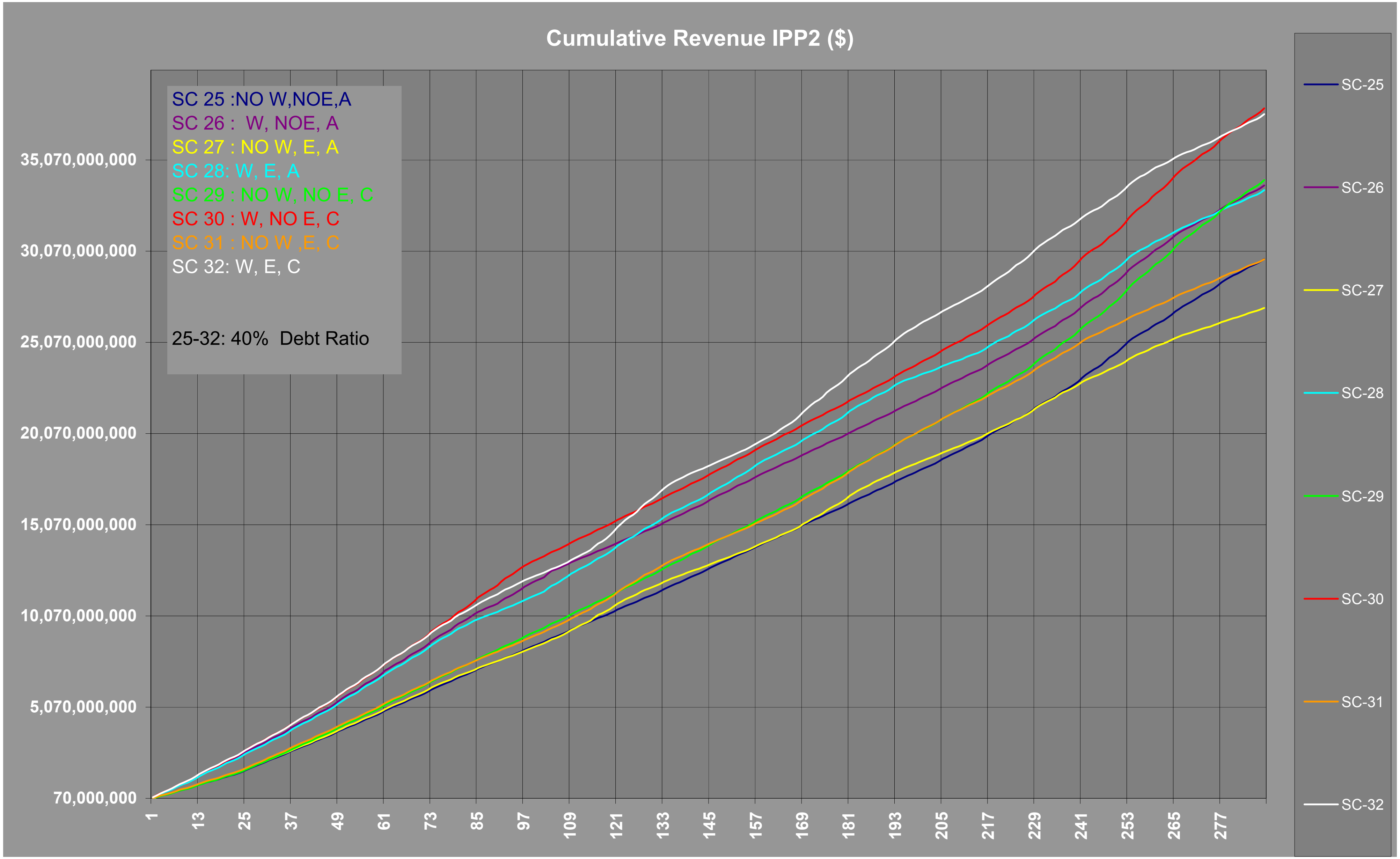
Cumulative Revenue IPP2 ($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
35,070,000,000
30,070,000,000
25,070,000,000
20,070,000,000
15,070,000,000
10,070,000,000
5,070,000,000
70,000,000
1
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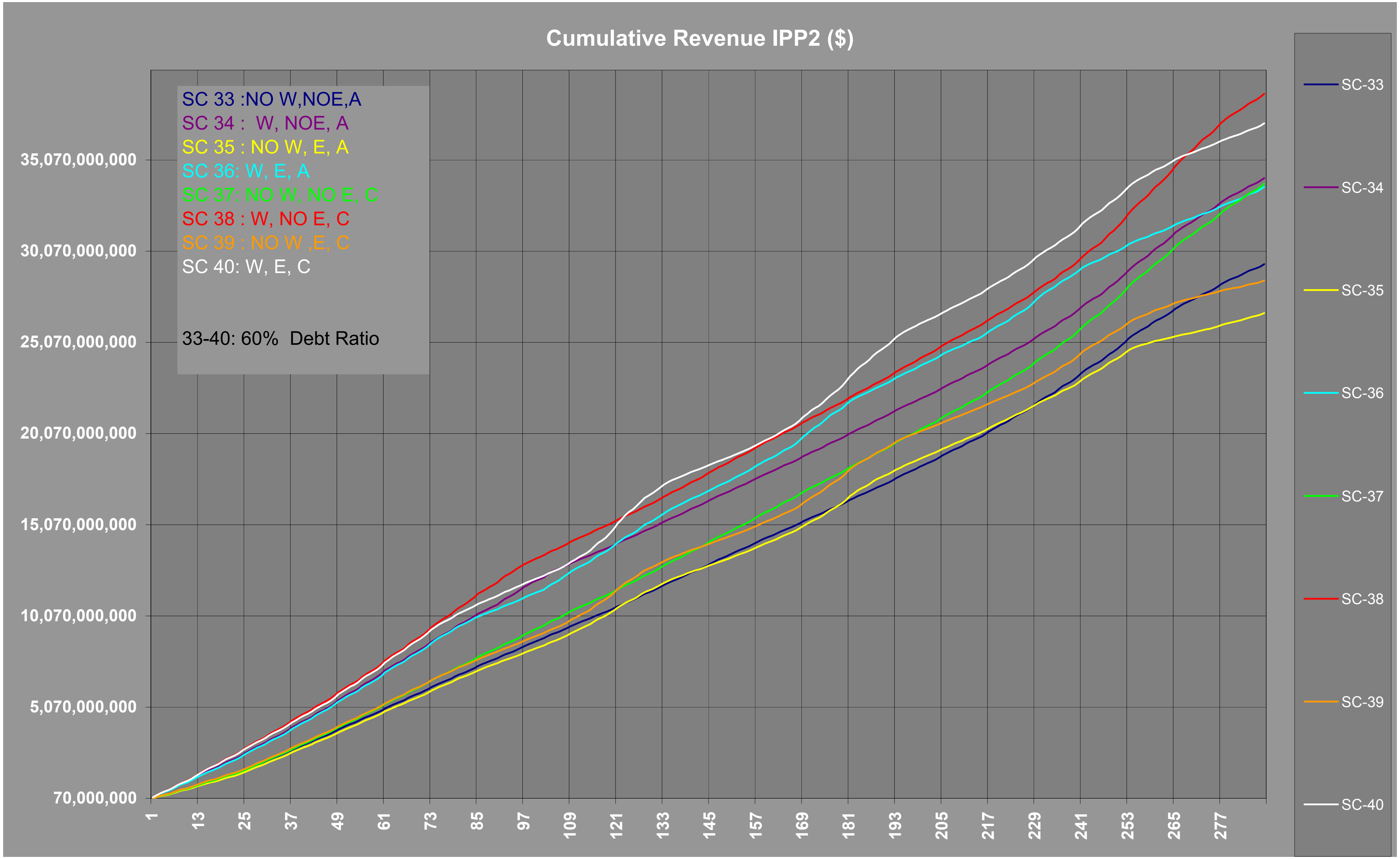
Cumulative Revenue IPP2 ($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
35,070,000,000
30,070,000,000
25,070,000,000
20,070,000,000
15,070,000,000
10,070,000,000
5,070,000,000
70,000,000
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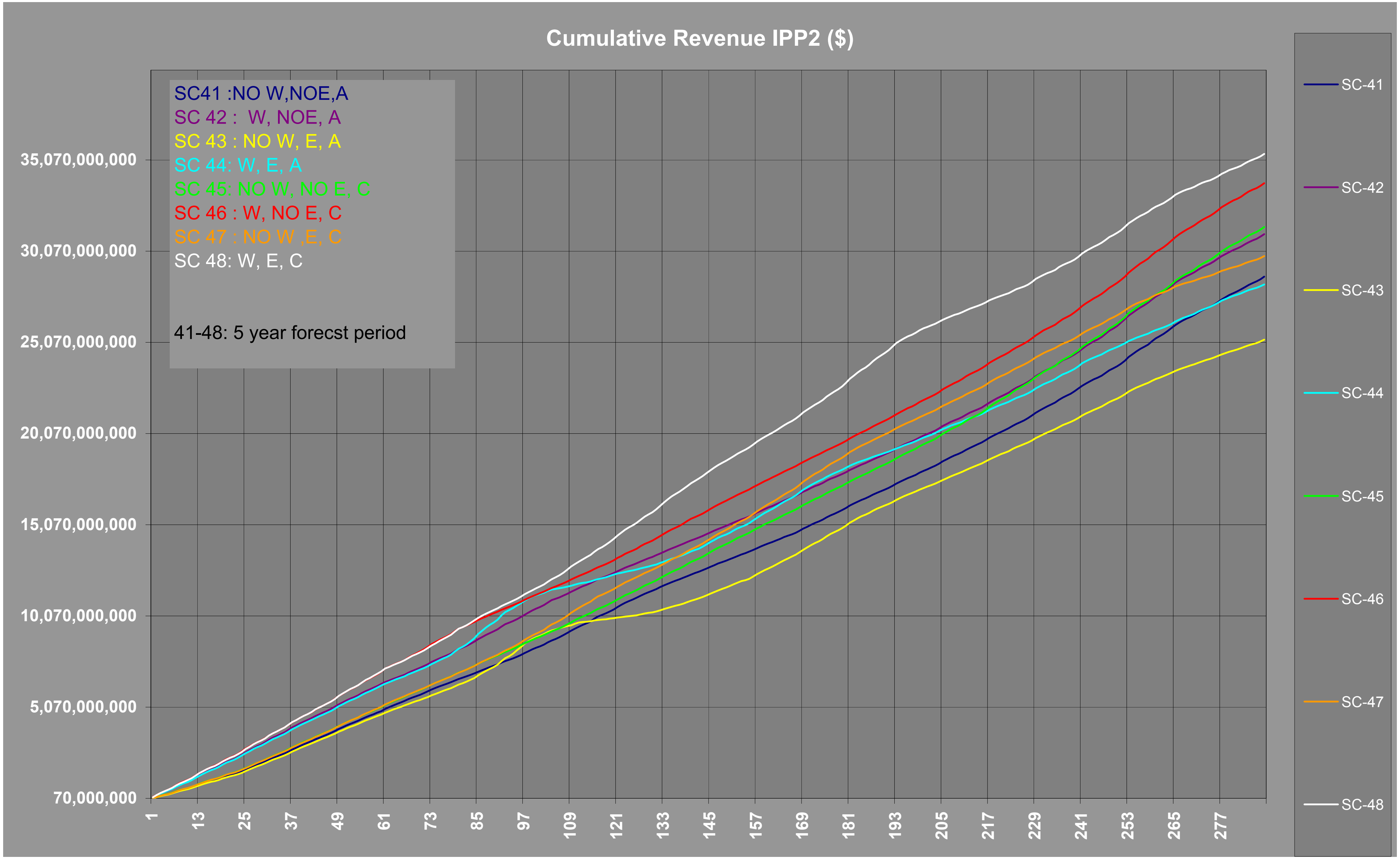
SC-40



Cumulative Revenue IPP2 ($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
35,070,000,000
30,070,000,000
25,070,000,000
20,070,000,000
15,070,000,000
10,070,000,000
5,070,000,000
70,000,000
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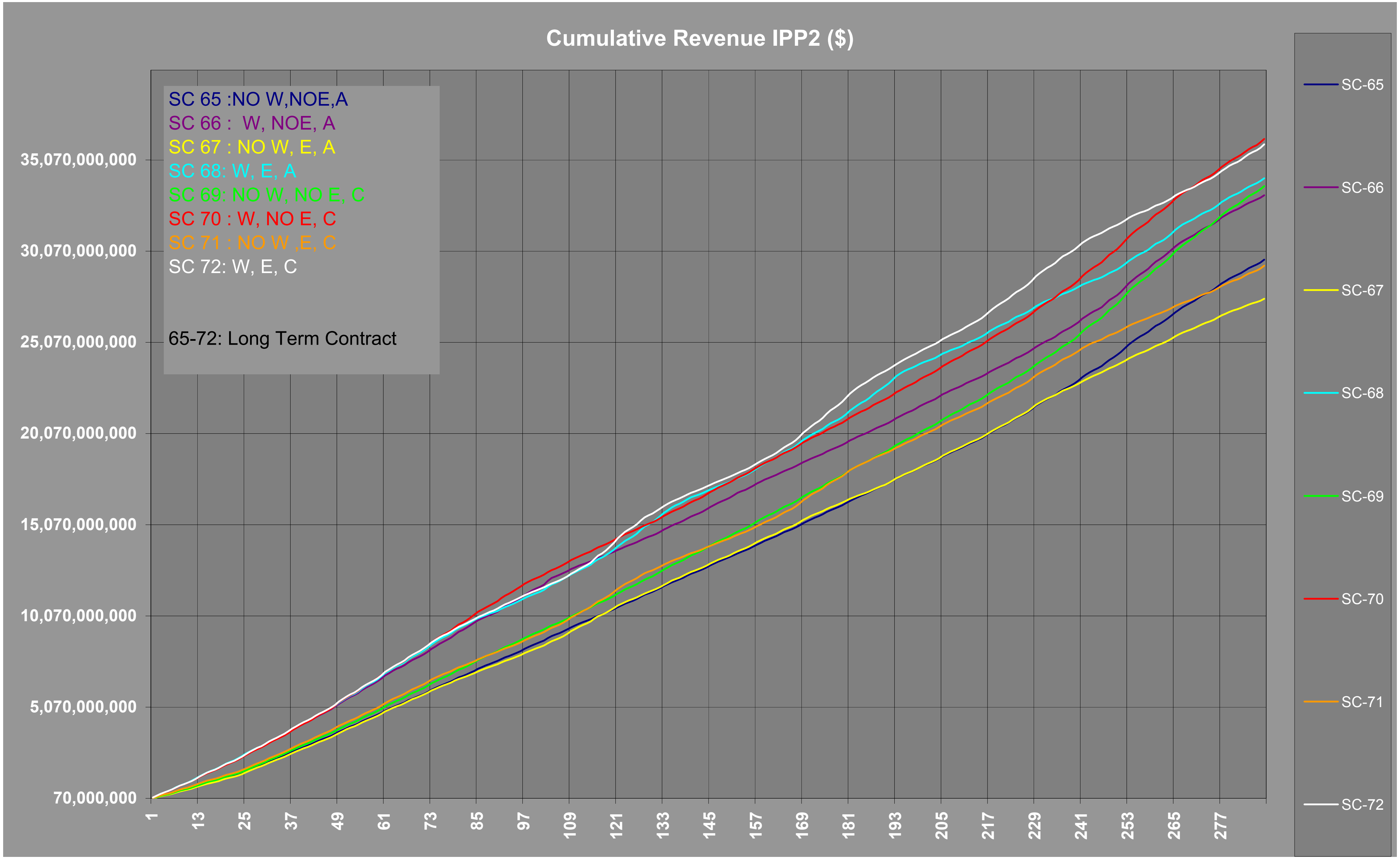
Cumulative Revenue IPP2 ($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
35,070,000,000
30,070,000,000
25,070,000,000
20,070,000,000
15,070,000,000
10,070,000,000
5,070,000,000
70,000,000
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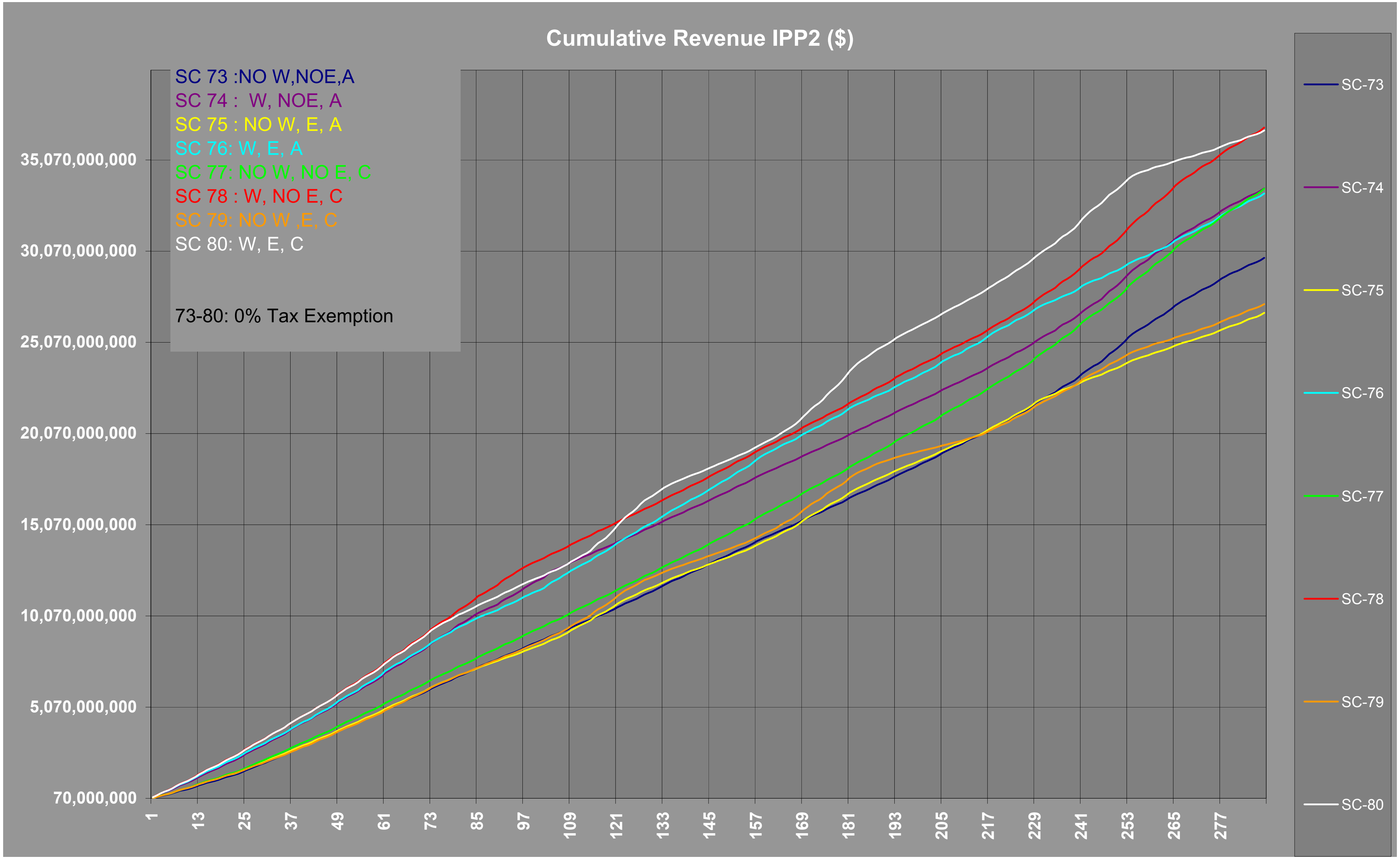
Cumulative Revenue IPP2 ($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
35,070,000,000
30,070,000,000
25,070,000,000
20,070,000,000
15,070,000,000
10,070,000,000
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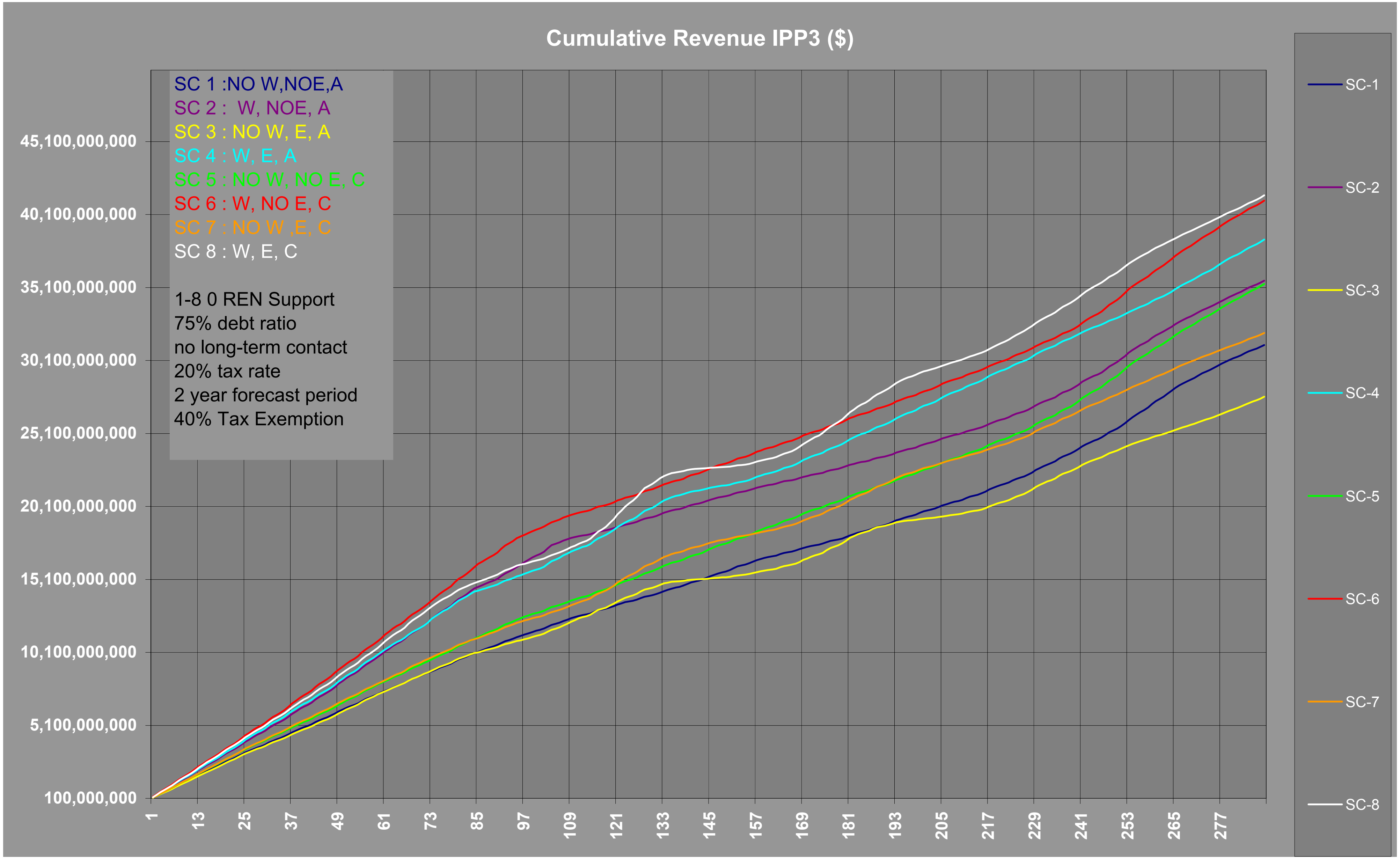
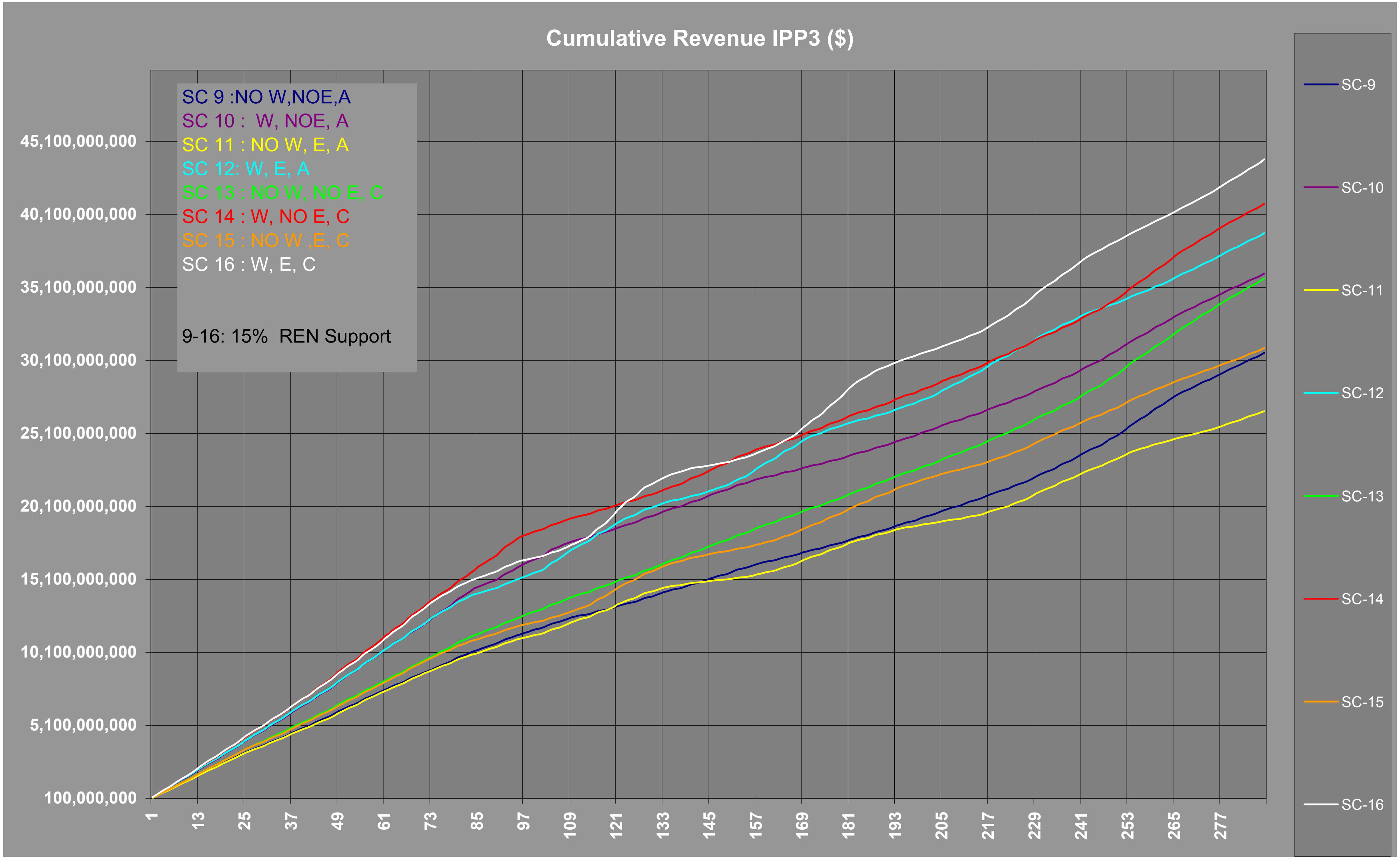
SC-78
SC-79
SC-80



Cumulative Revenue IPP3 ($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
45,100,000,000
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Cumulative Revenue IPP3 ($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
45,100,000,000
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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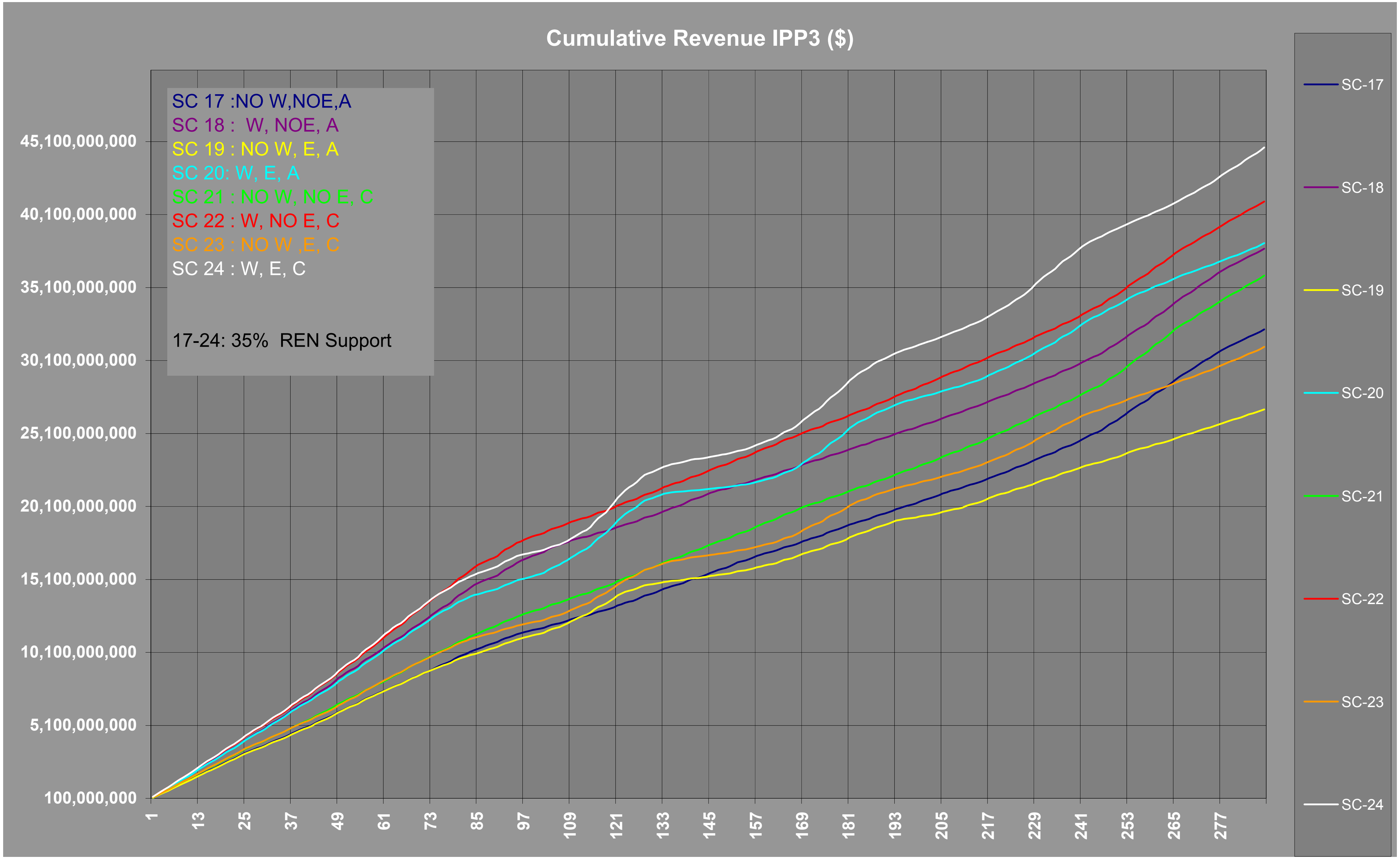
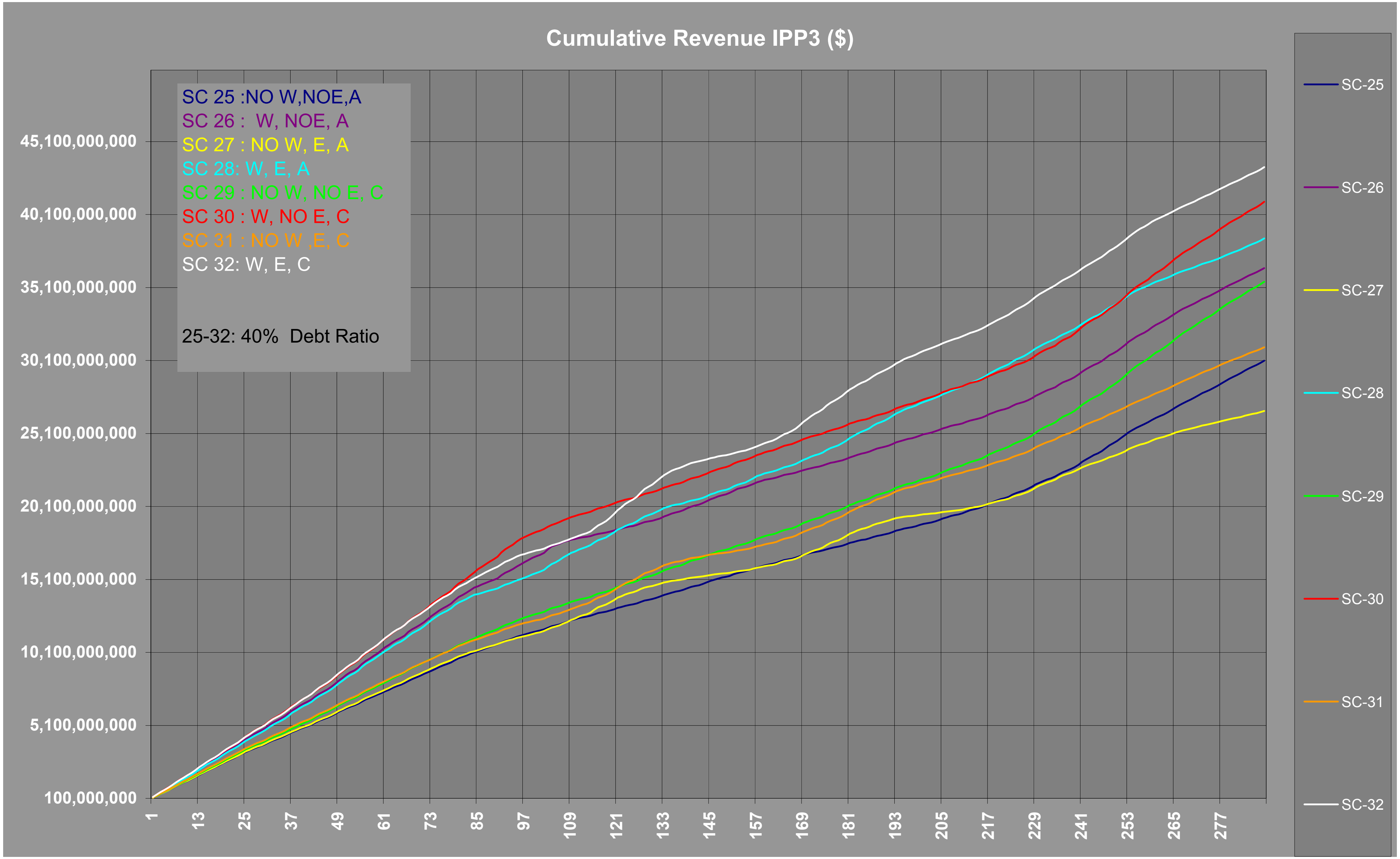
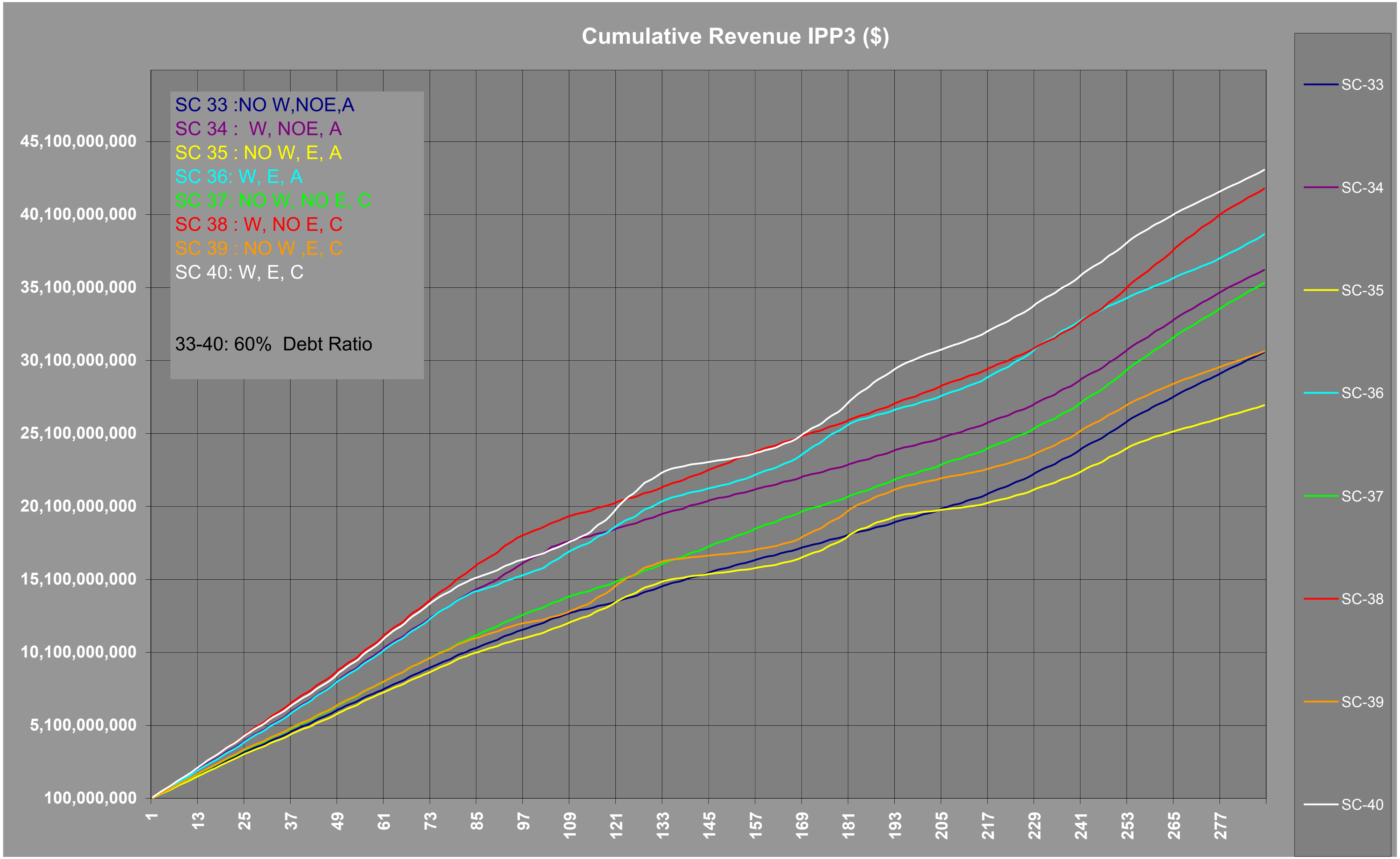
SC-14
SC-15
SC-16



Cumulative Revenue IPP3 ($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
45,100,000,000
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24


Cumulative Revenue IPP3 ($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
45,100,000,000
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32


Cumulative Revenue IPP3 ($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
45,100,000,000
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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SC-34
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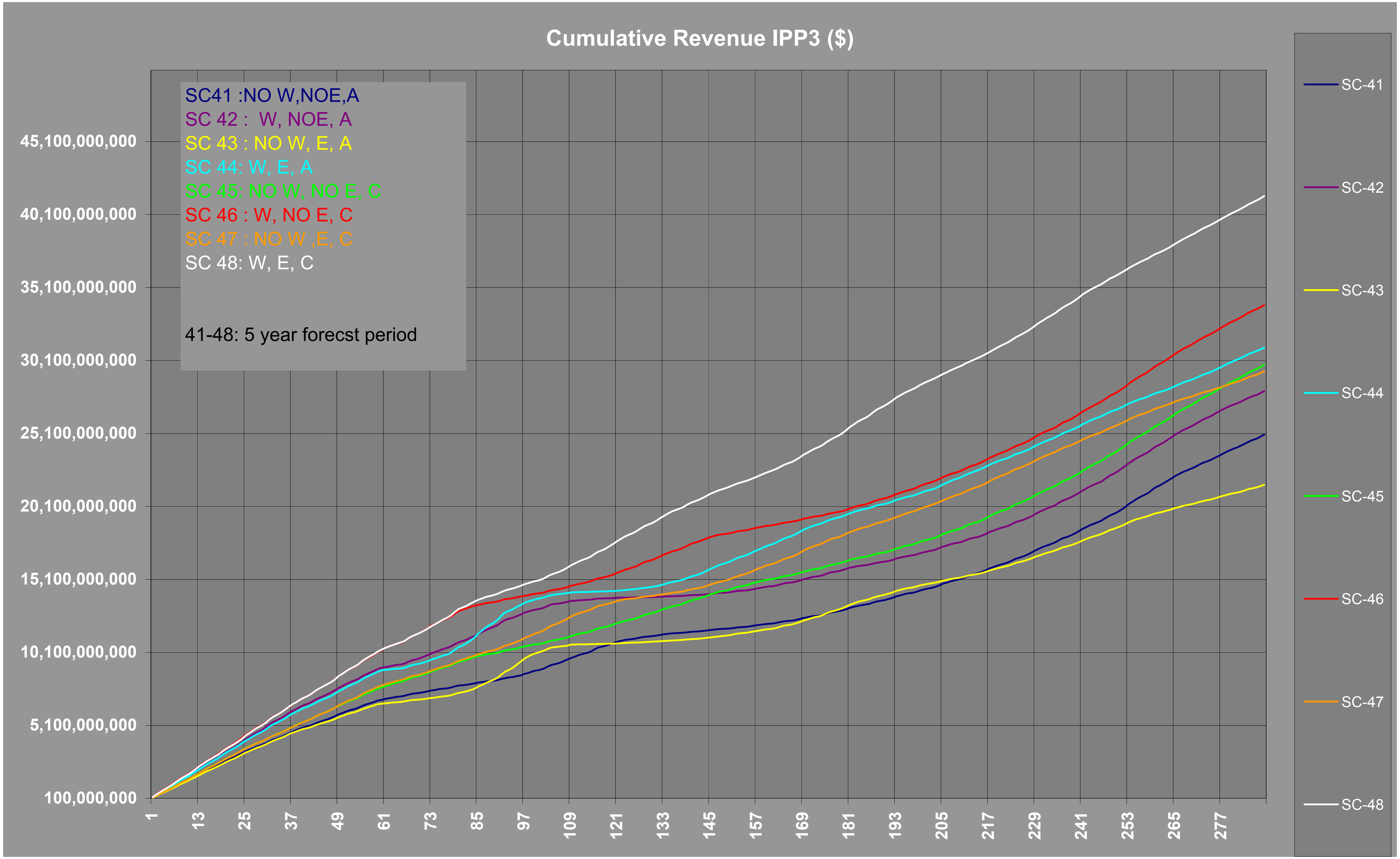
SC-38
SC-39
SC-40



Cumulative Revenue IPP3 ($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
45,100,000,000
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
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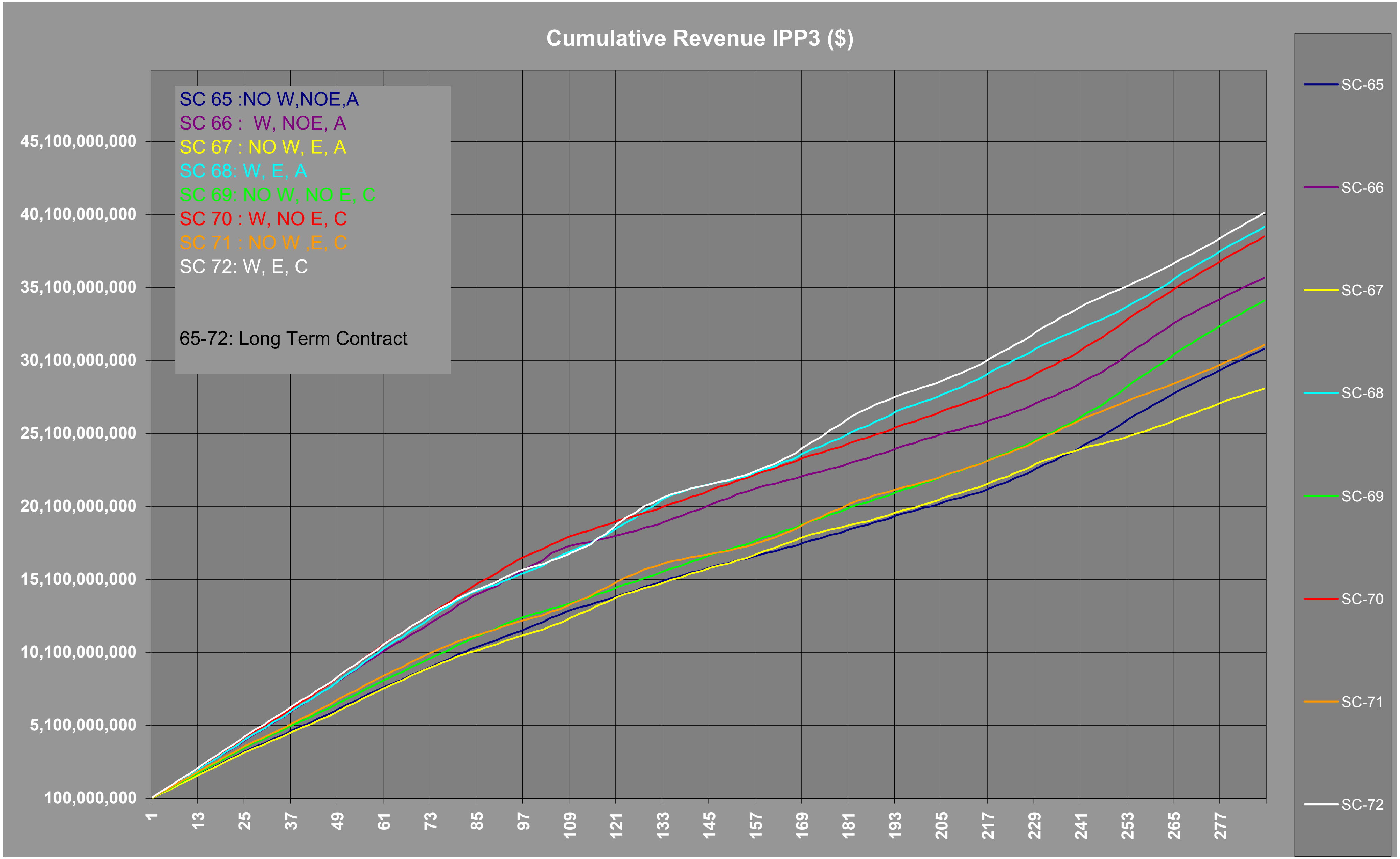
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48


Cumulative Revenue IPP3 ($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
45,100,000,000
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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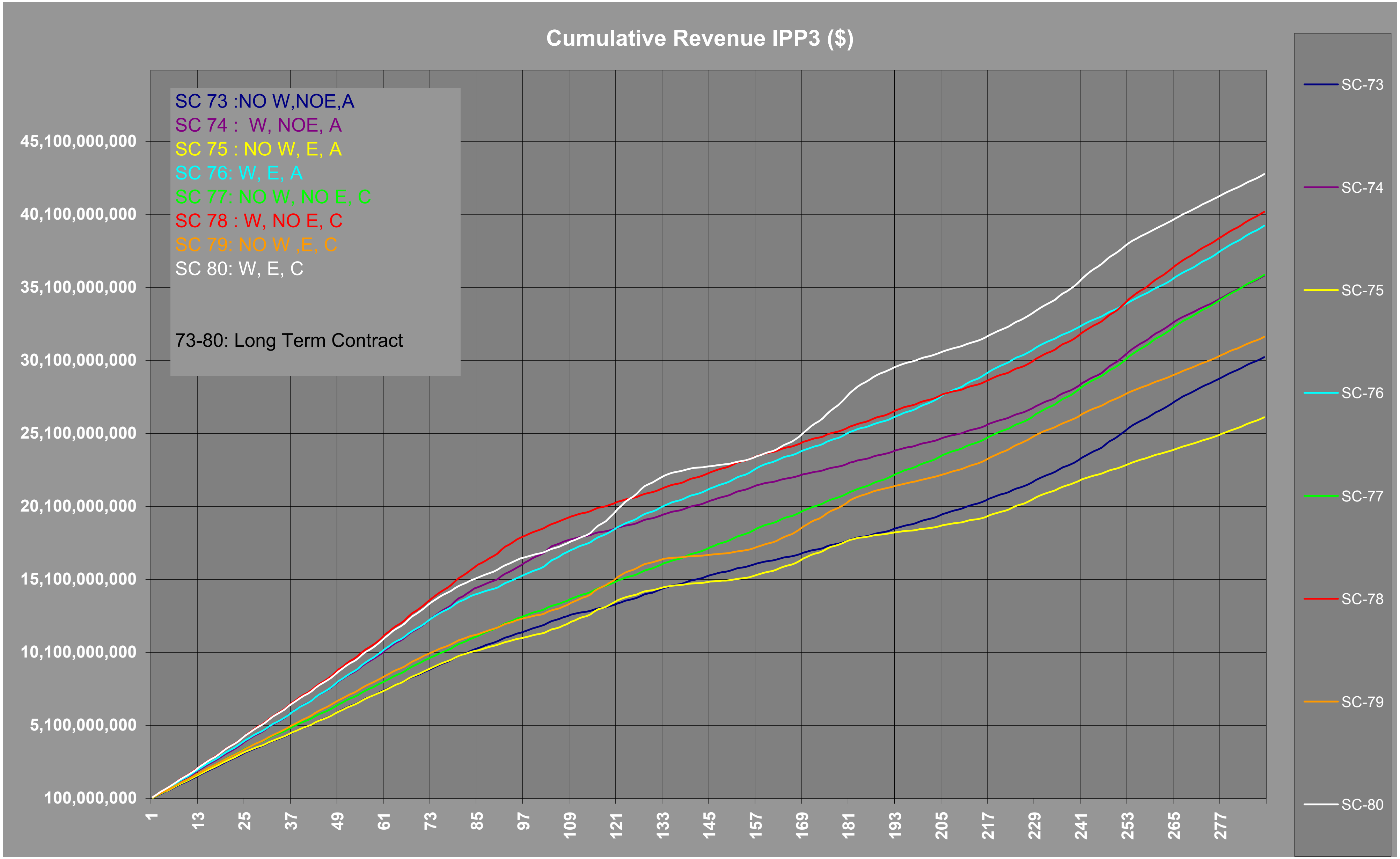
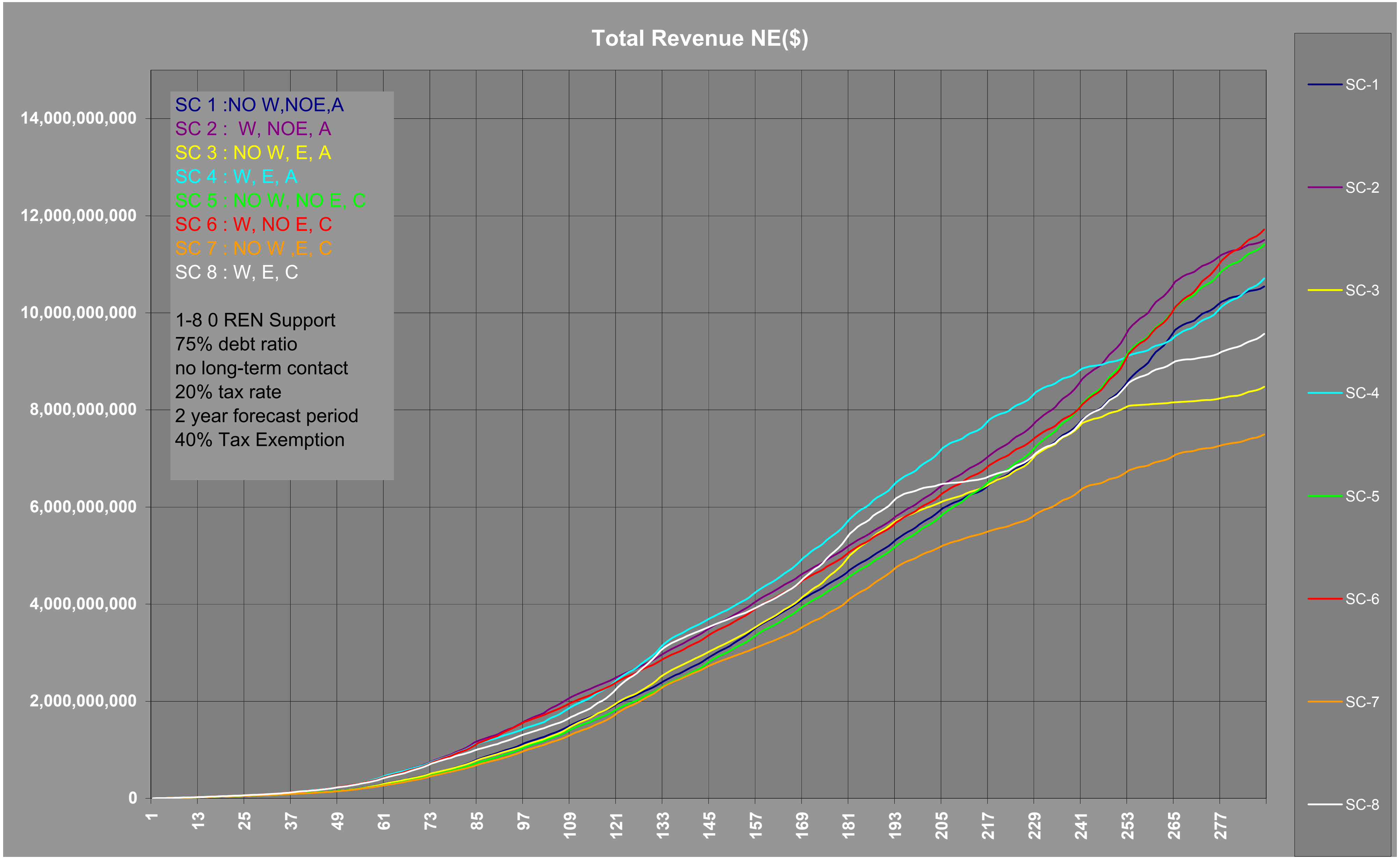
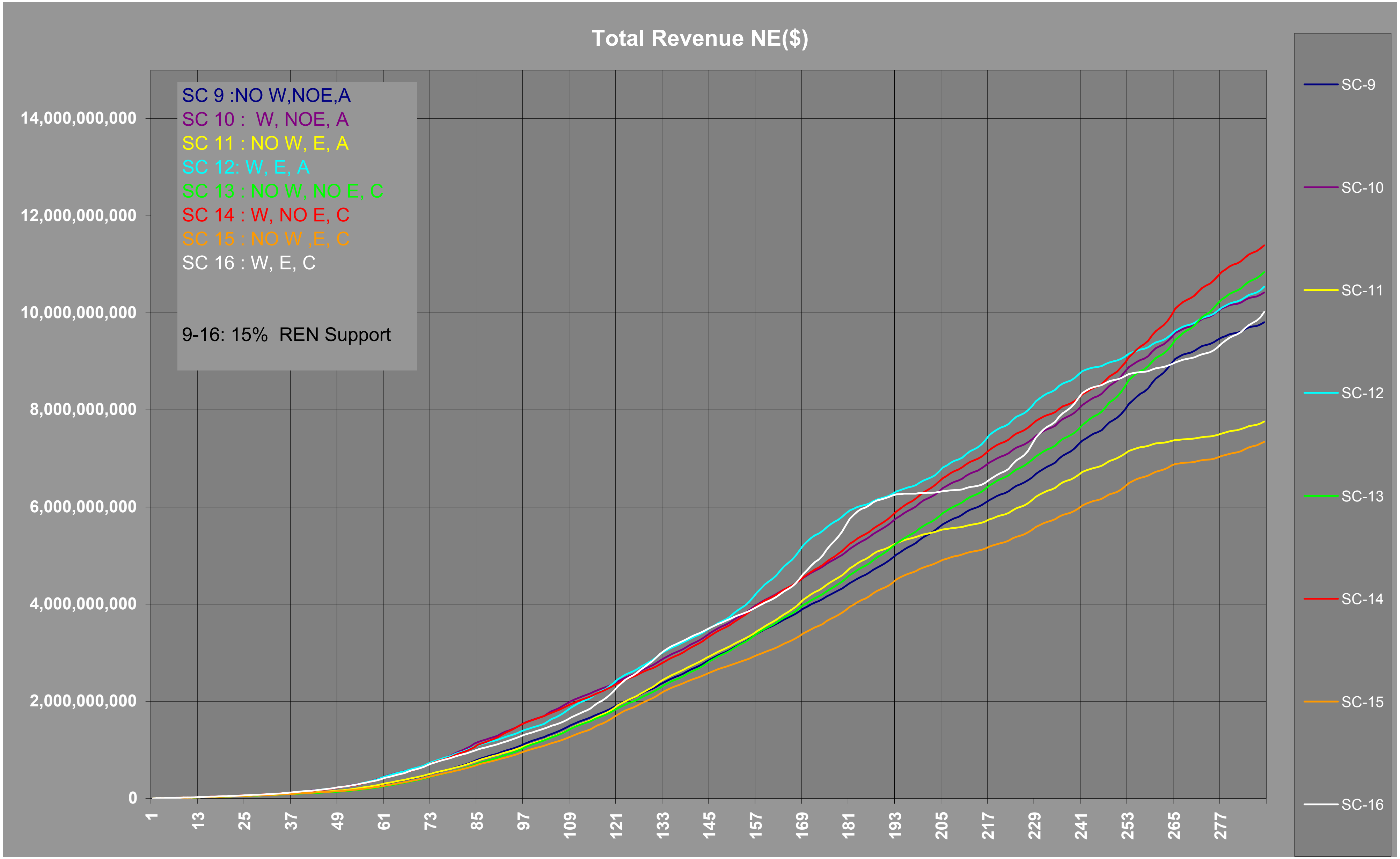
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



Cumulative Revenue IPP3 ($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
45,100,000,000
40,100,000,000
35,100,000,000
30,100,000,000
25,100,000,000
20,100,000,000
15,100,000,000
10,100,000,000
5,100,000,000
100,000,000
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



Total Revenue NE($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
14,000,000,000
12,000,000,000
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Total Revenue NE($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
14,000,000,000
12,000,000,000
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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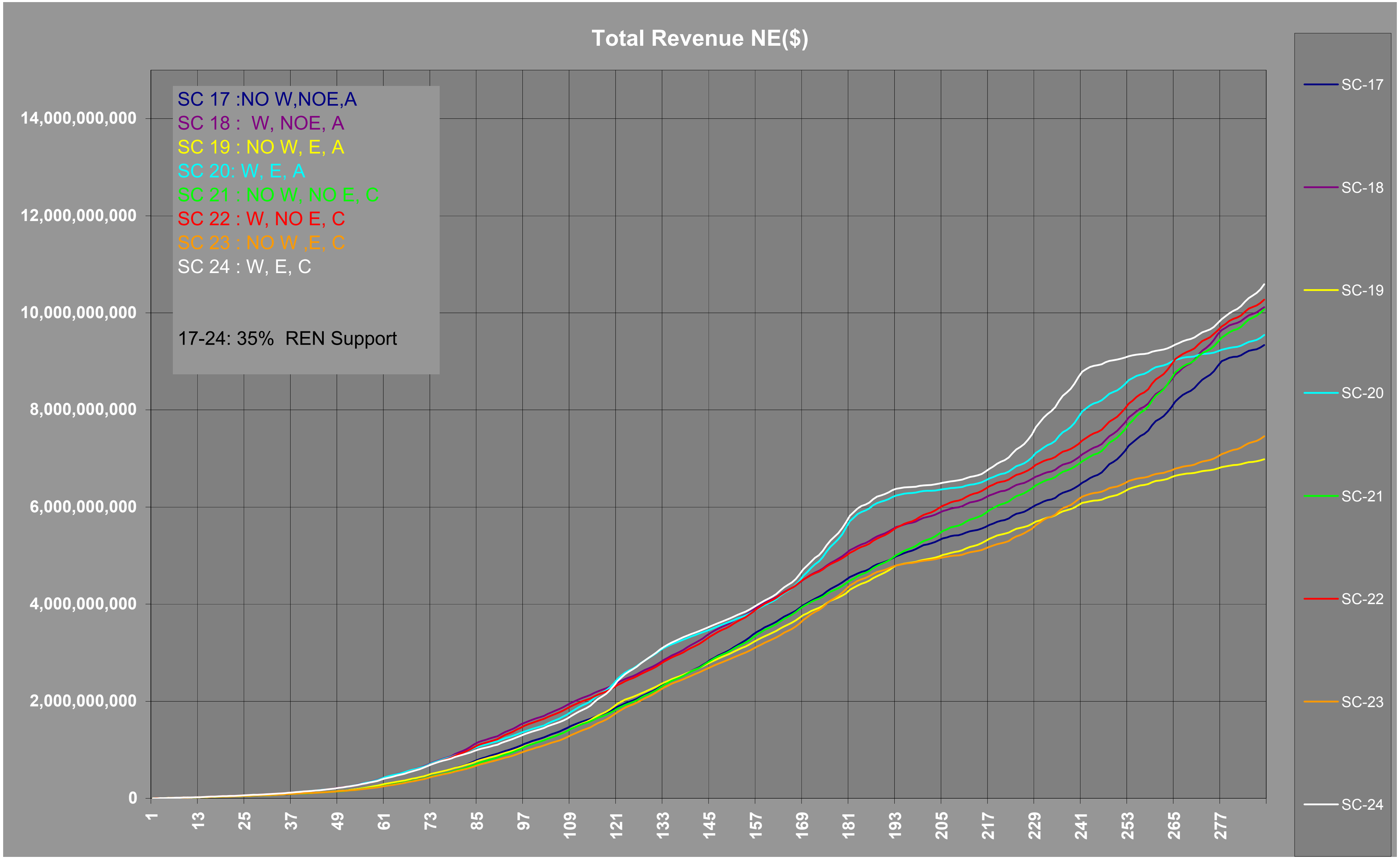
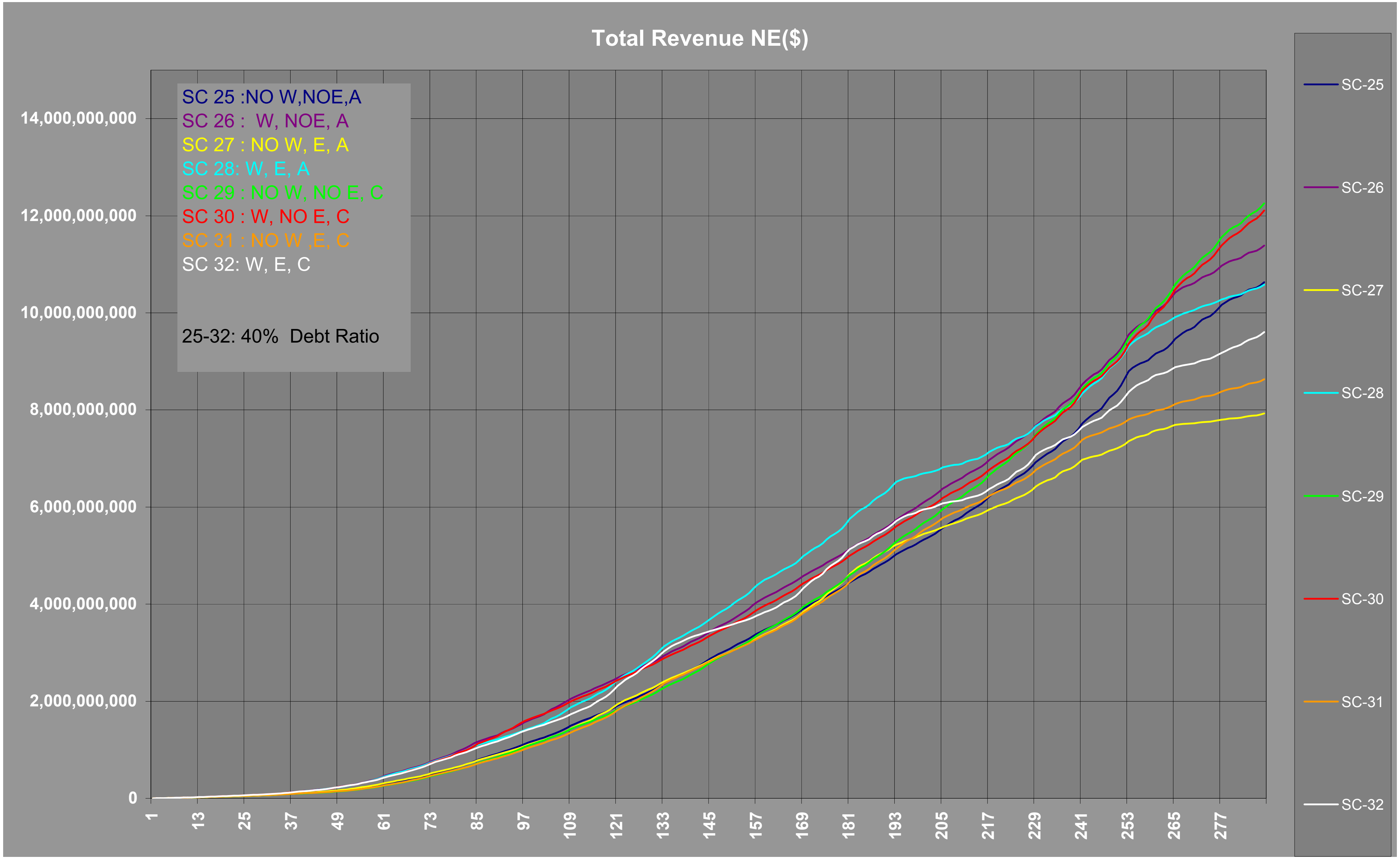
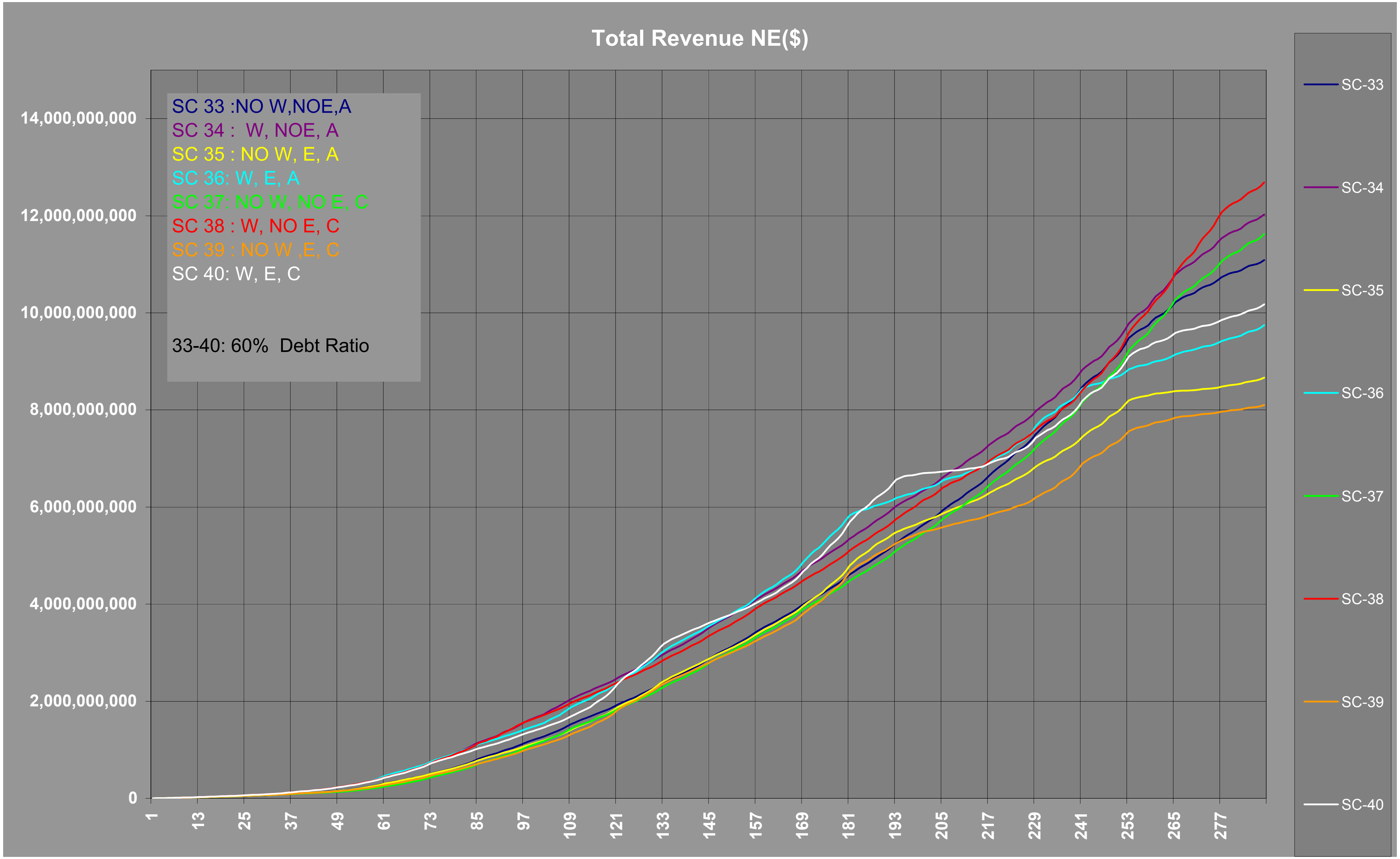
SC-14
SC-15
SC-16

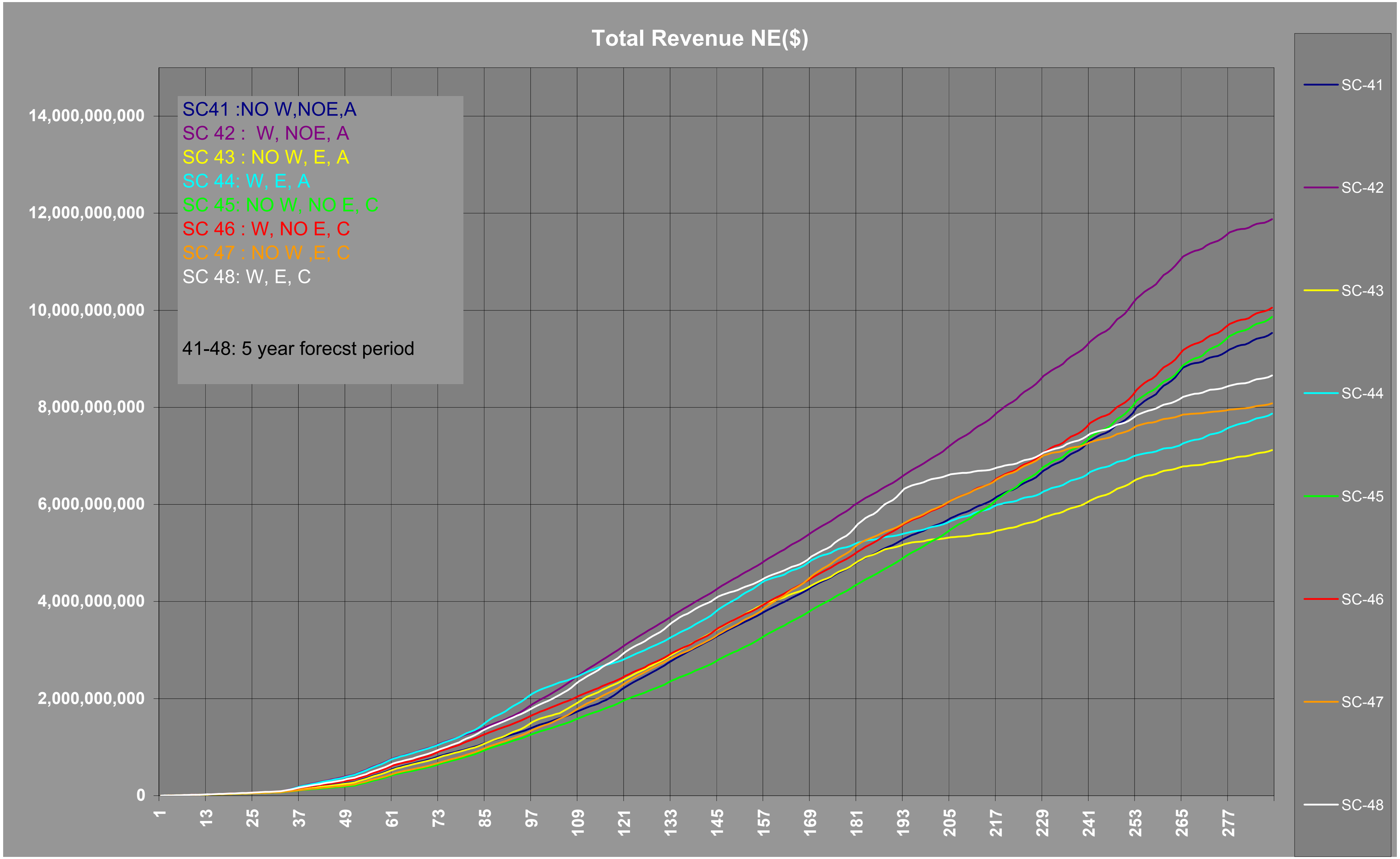


Total Revenue NE($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
14,000,000,000
12,000,000,000
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24


Total Revenue NE($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
14,000,000,000
12,000,000,000
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



Total Revenue NE($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
14,000,000,000
12,000,000,000
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40


Total Revenue NE($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
14,000,000,000
12,000,000,000
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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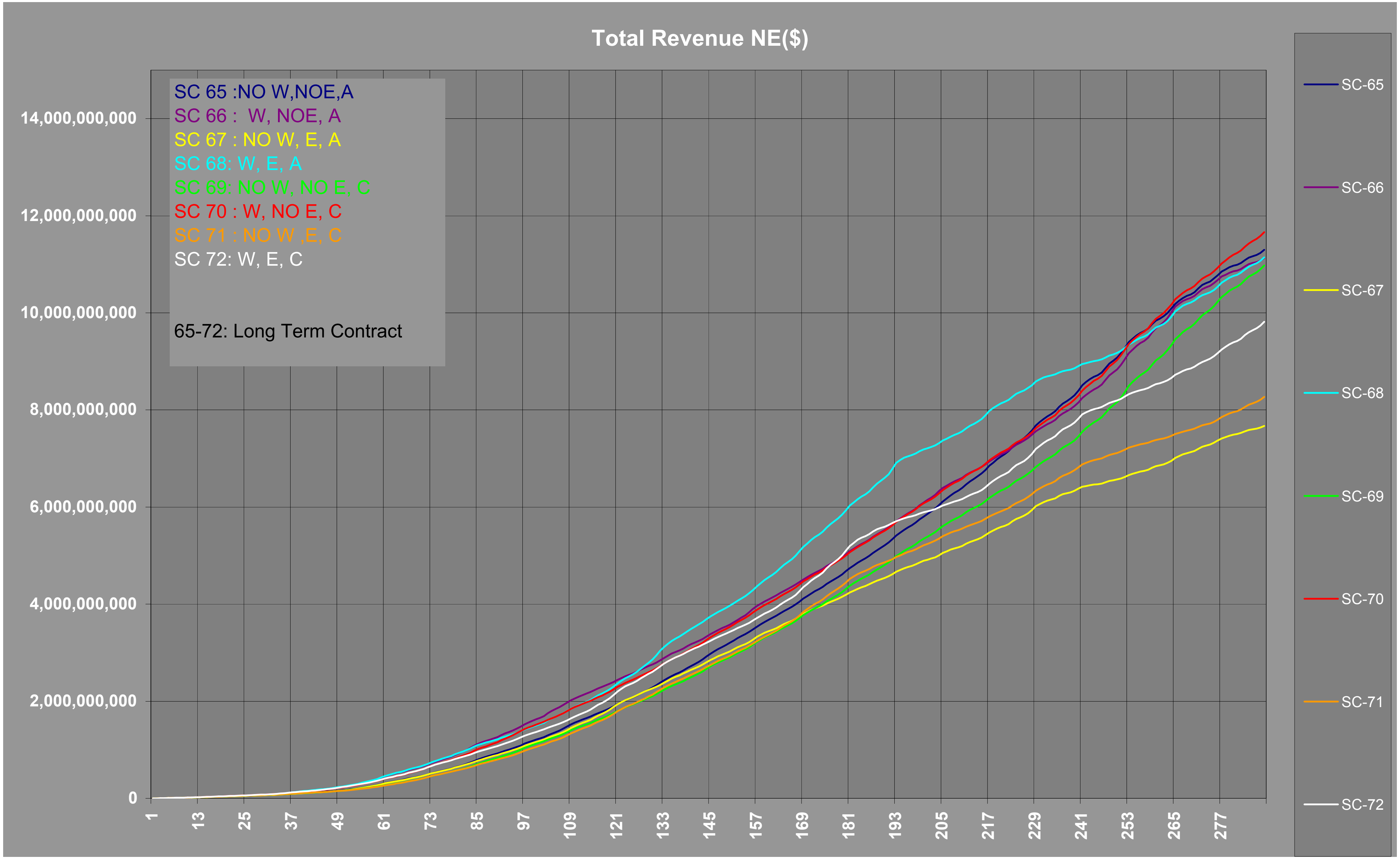
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48


Total Revenue NE($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
14,000,000,000
12,000,000,000
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
1
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25
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181
193
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SC-66
SC-67
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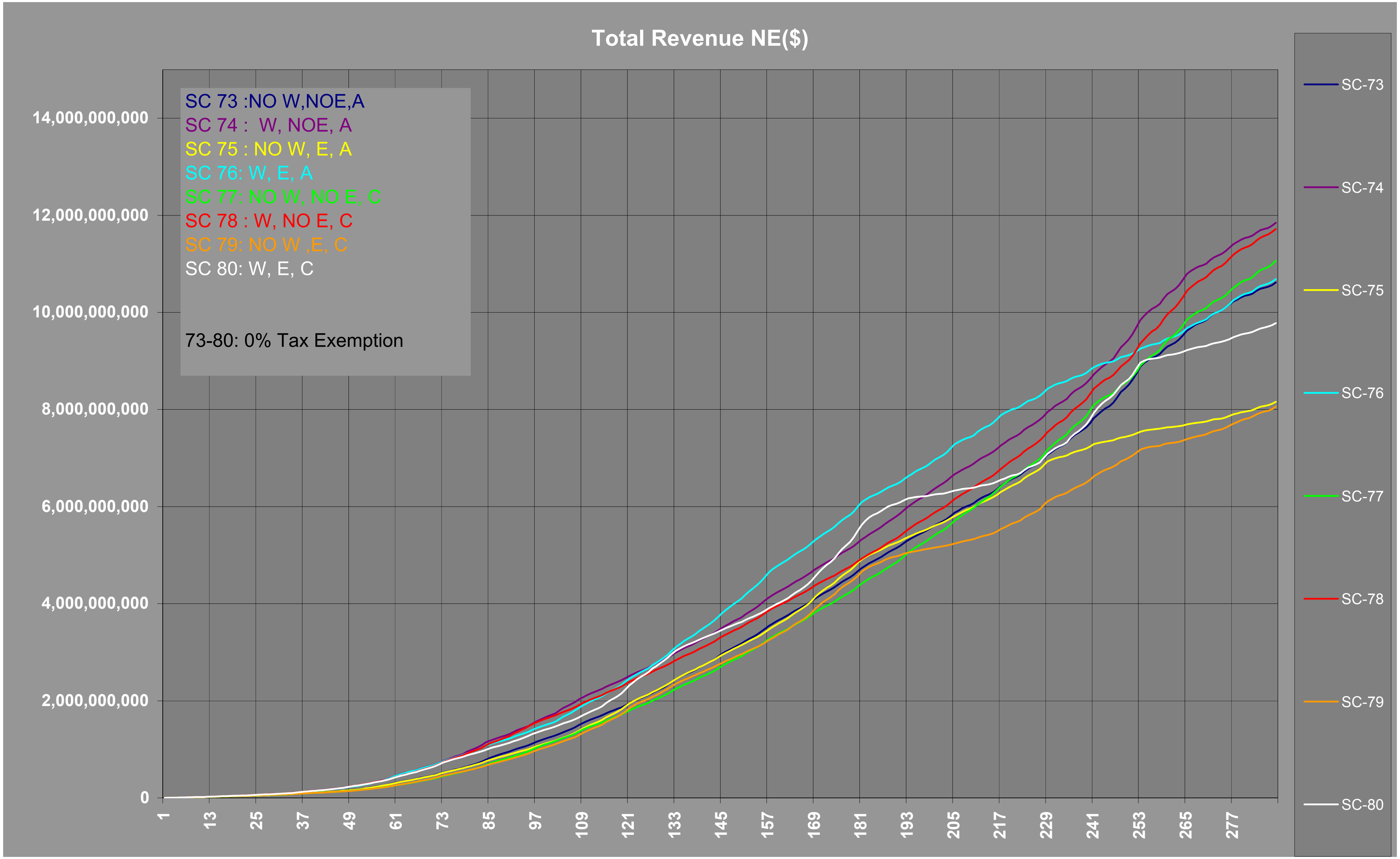
SC-69
SC-70
SC-71
SC-72


Total Revenue NE($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
14,000,000,000
12,000,000,000
10,000,000,000
8,000,000,000
6,000,000,000
4,000,000,000
2,000,000,000
0
1
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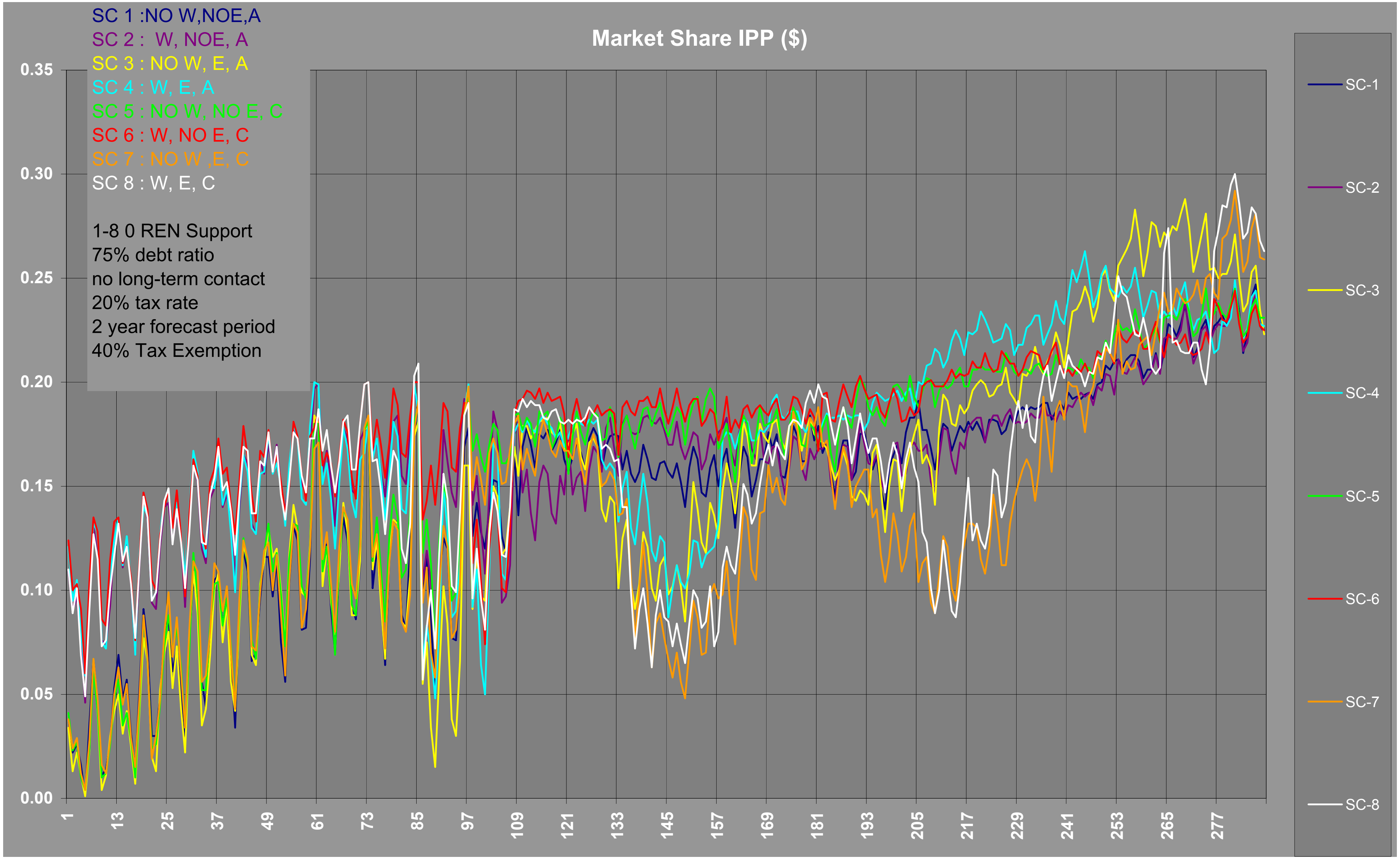
SC-79
SC-80



Market Share IPP ($)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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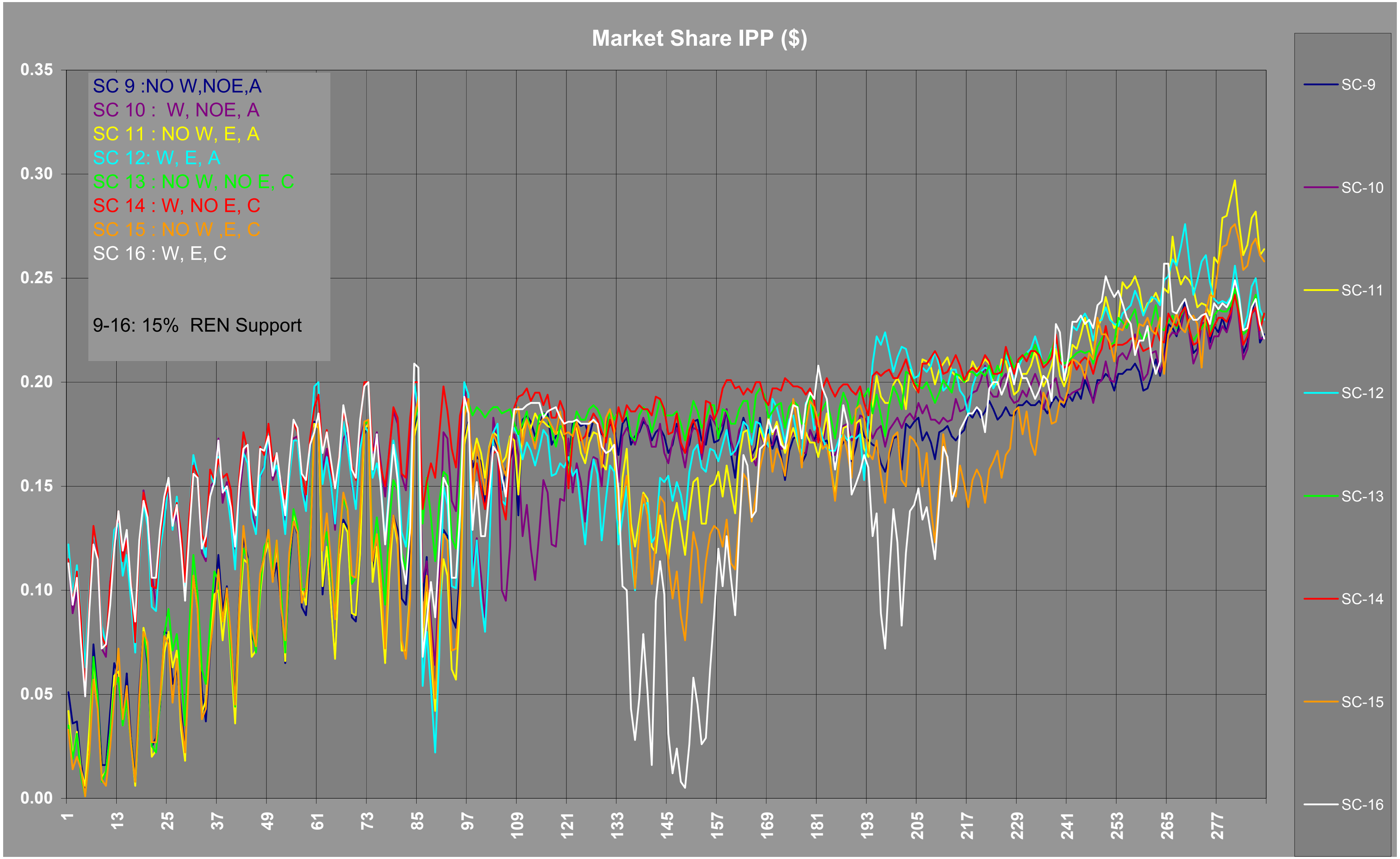
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Market Share IPP ($)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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229
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253
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277
SC-9
SC-10
SC-11
SC-12
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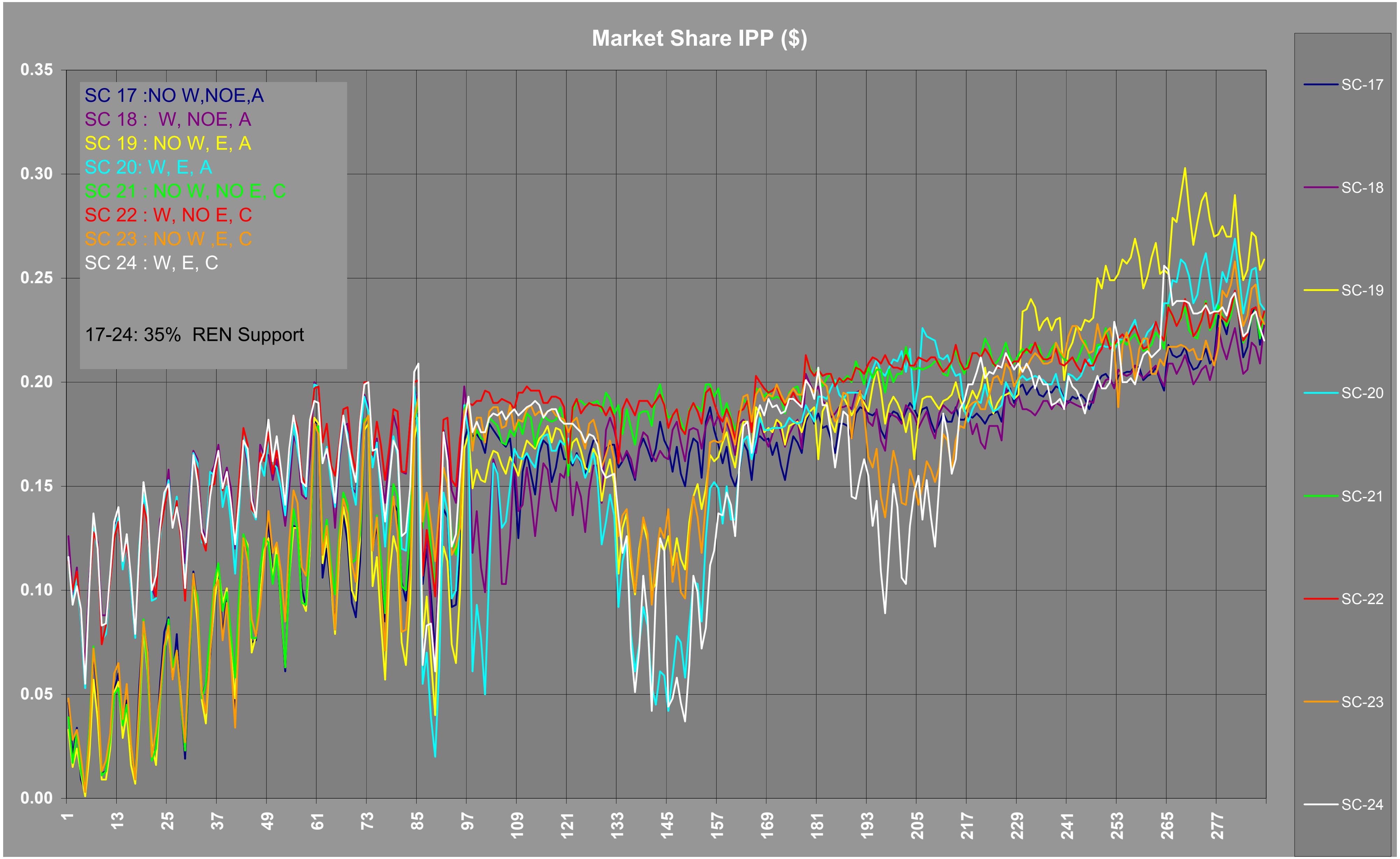
SC-14
SC-15
SC-16


Market Share IPP ($)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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229
241
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265
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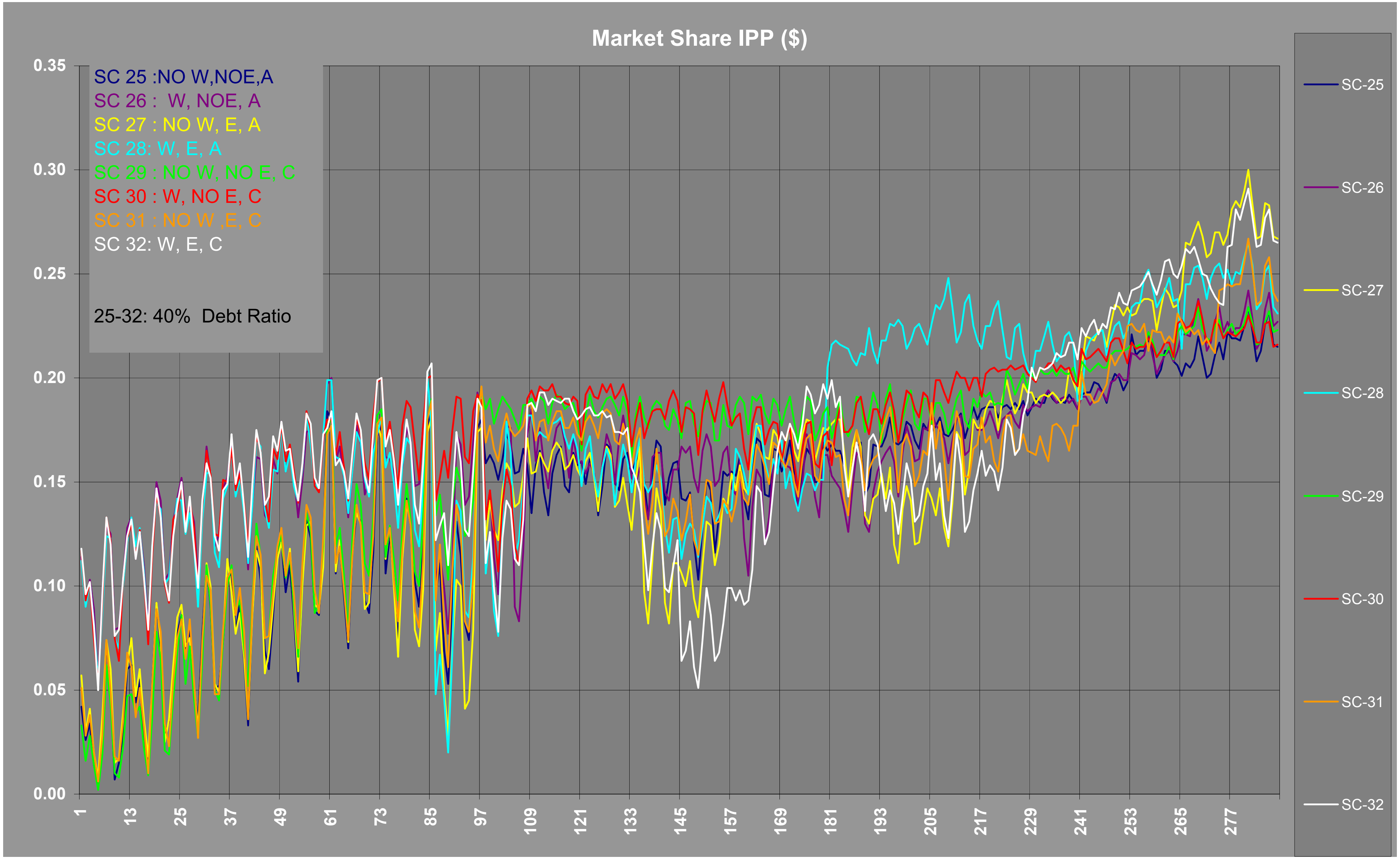
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24



Market Share IPP ($)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
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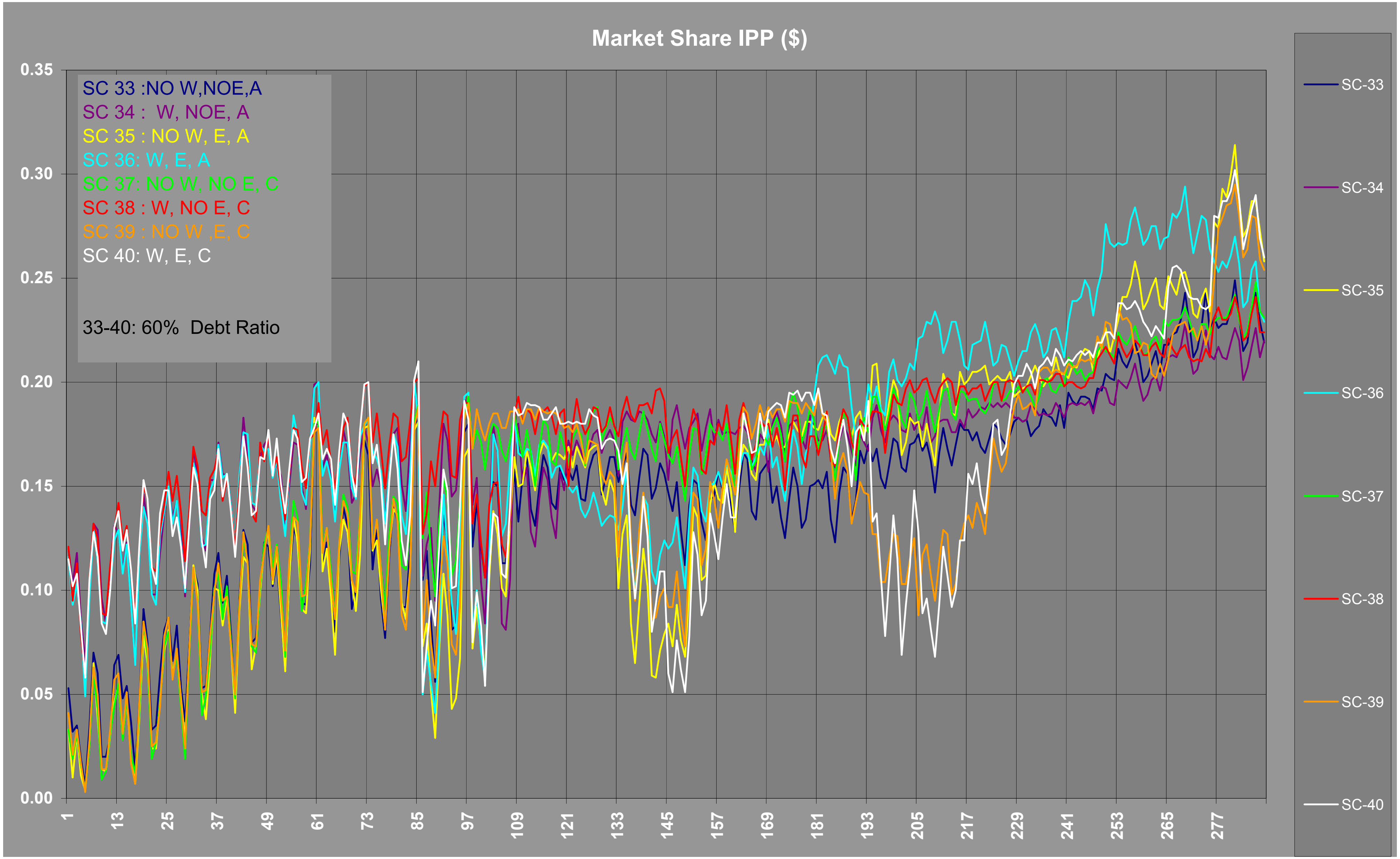
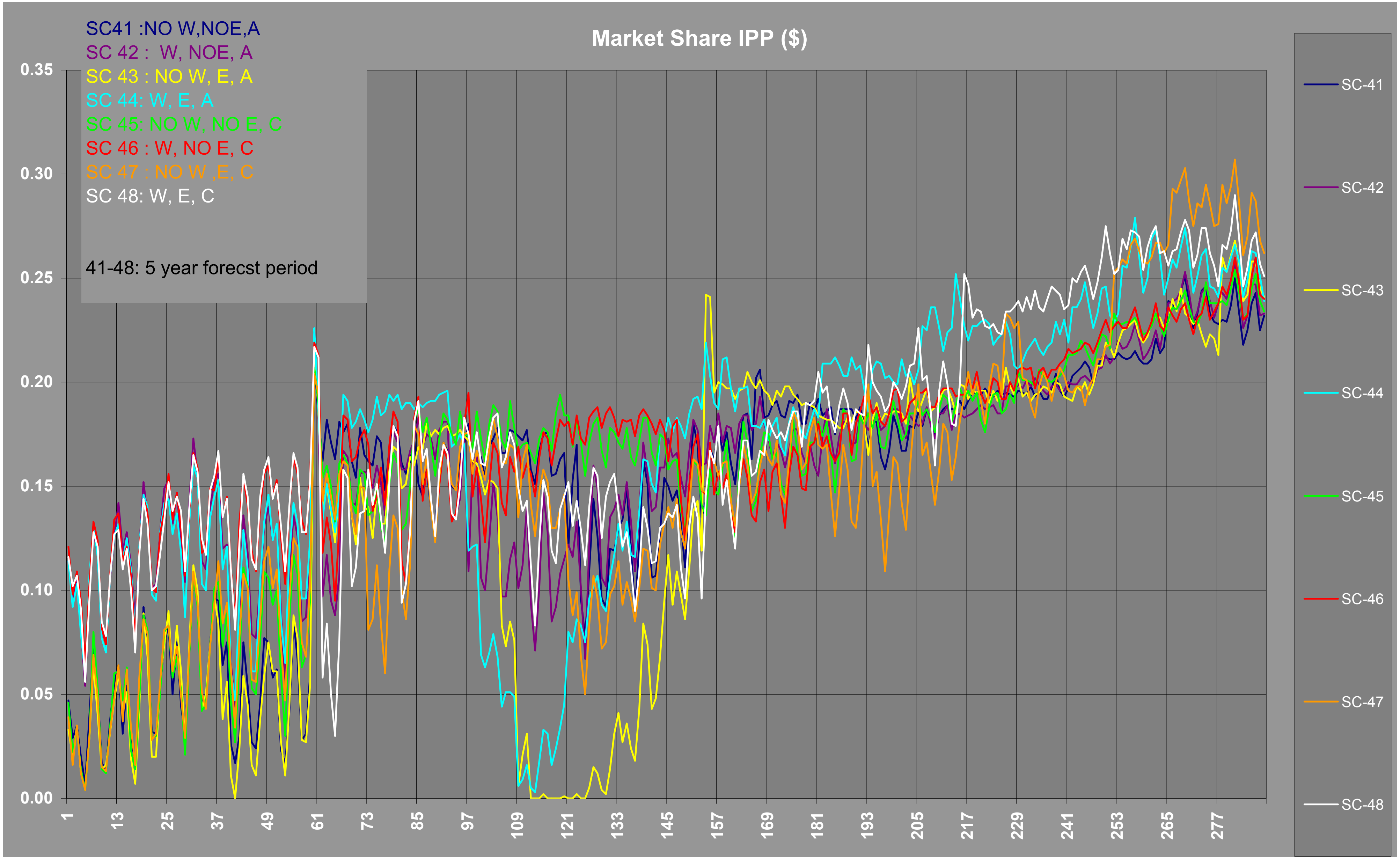
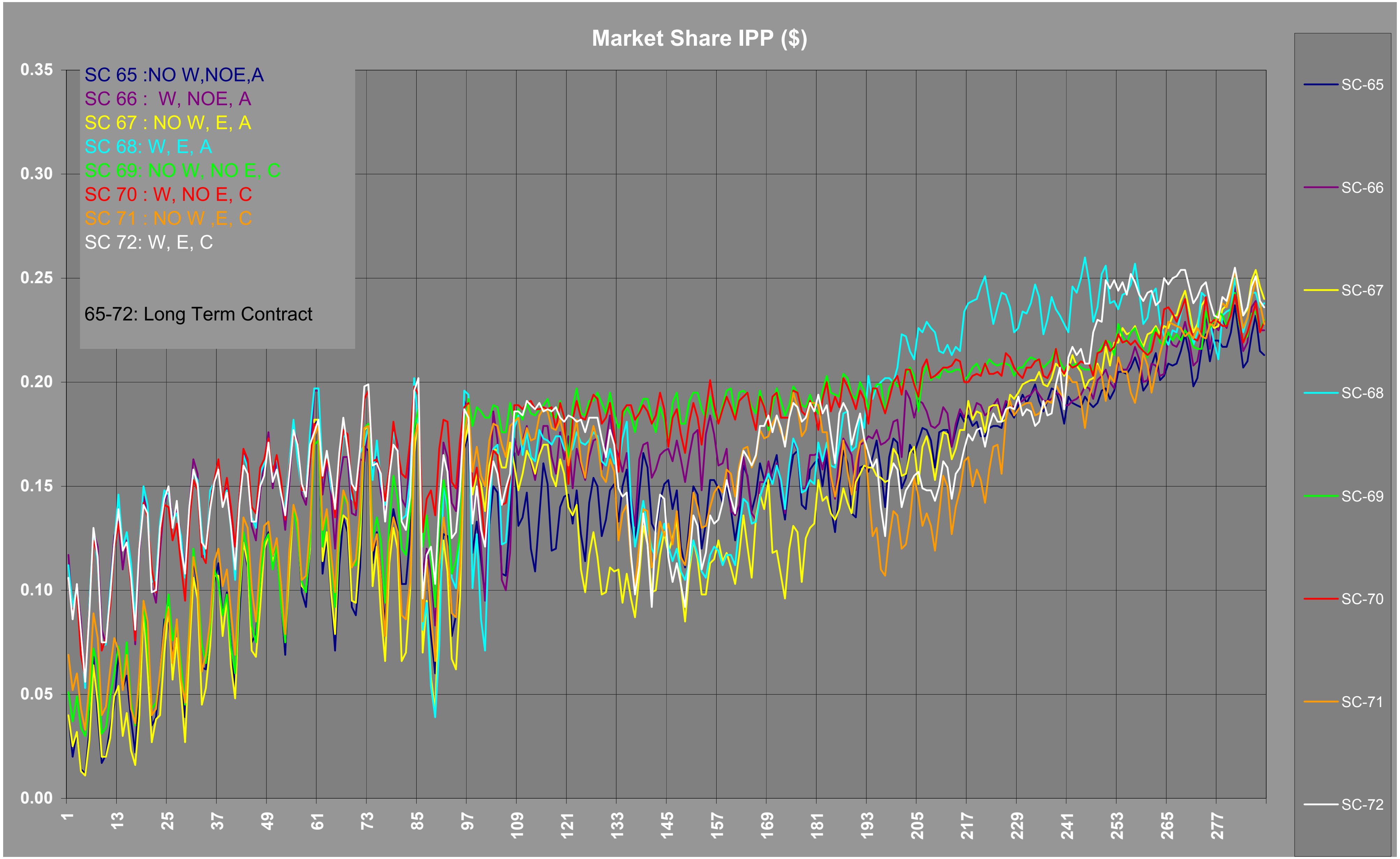
SC-30
SC-31
SC-32

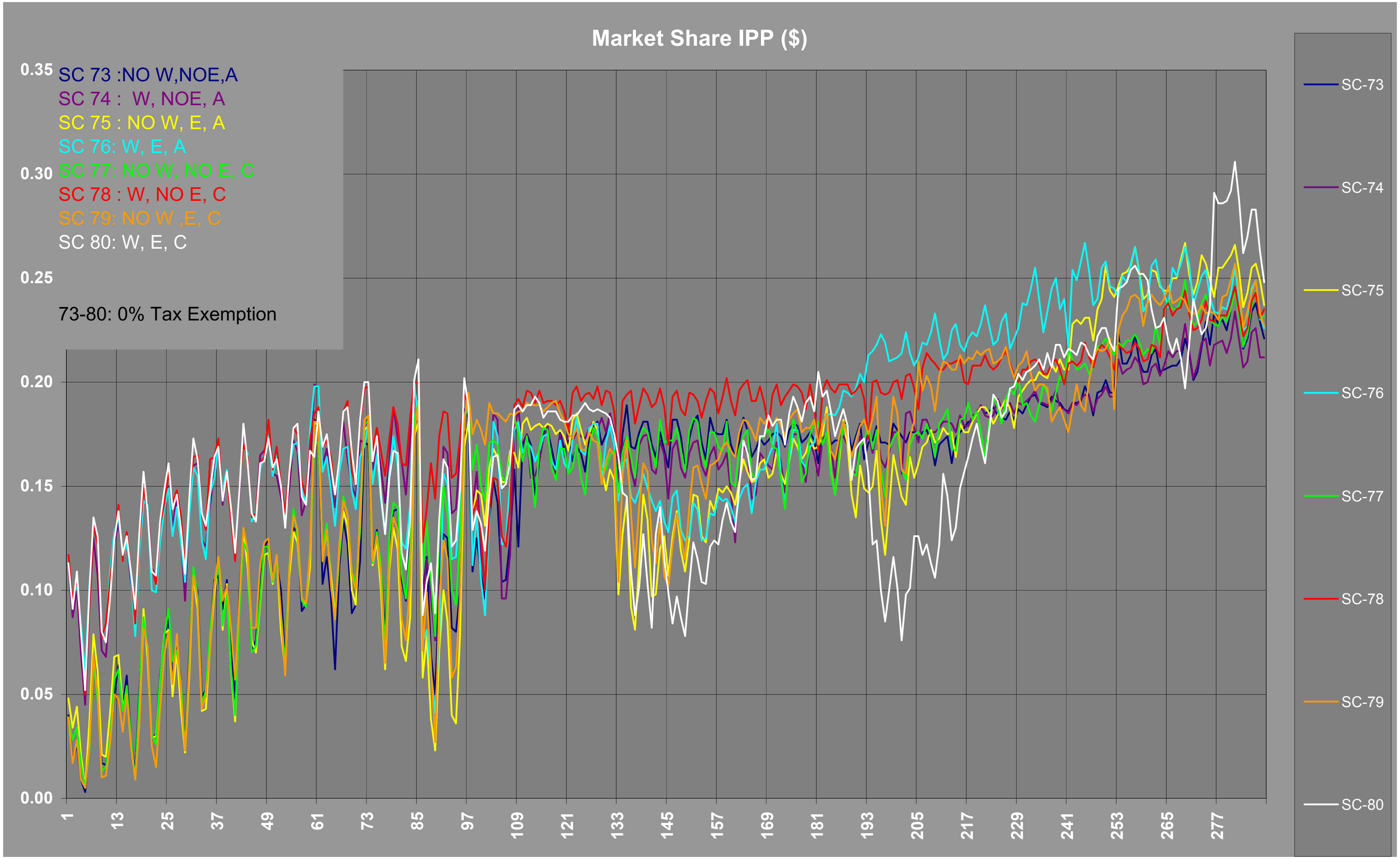


Market Share IPP ($)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

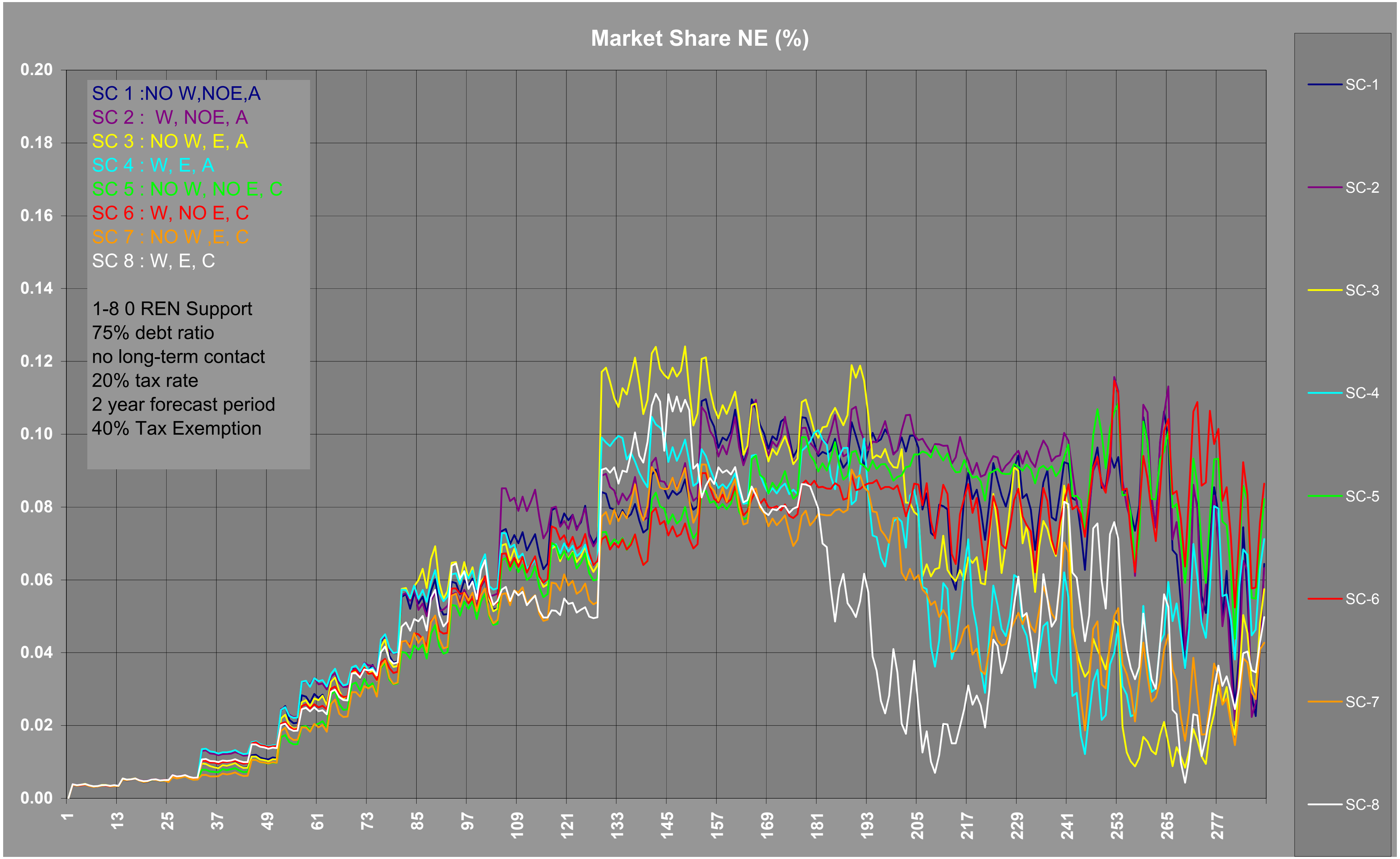

Market Share IPP ($)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



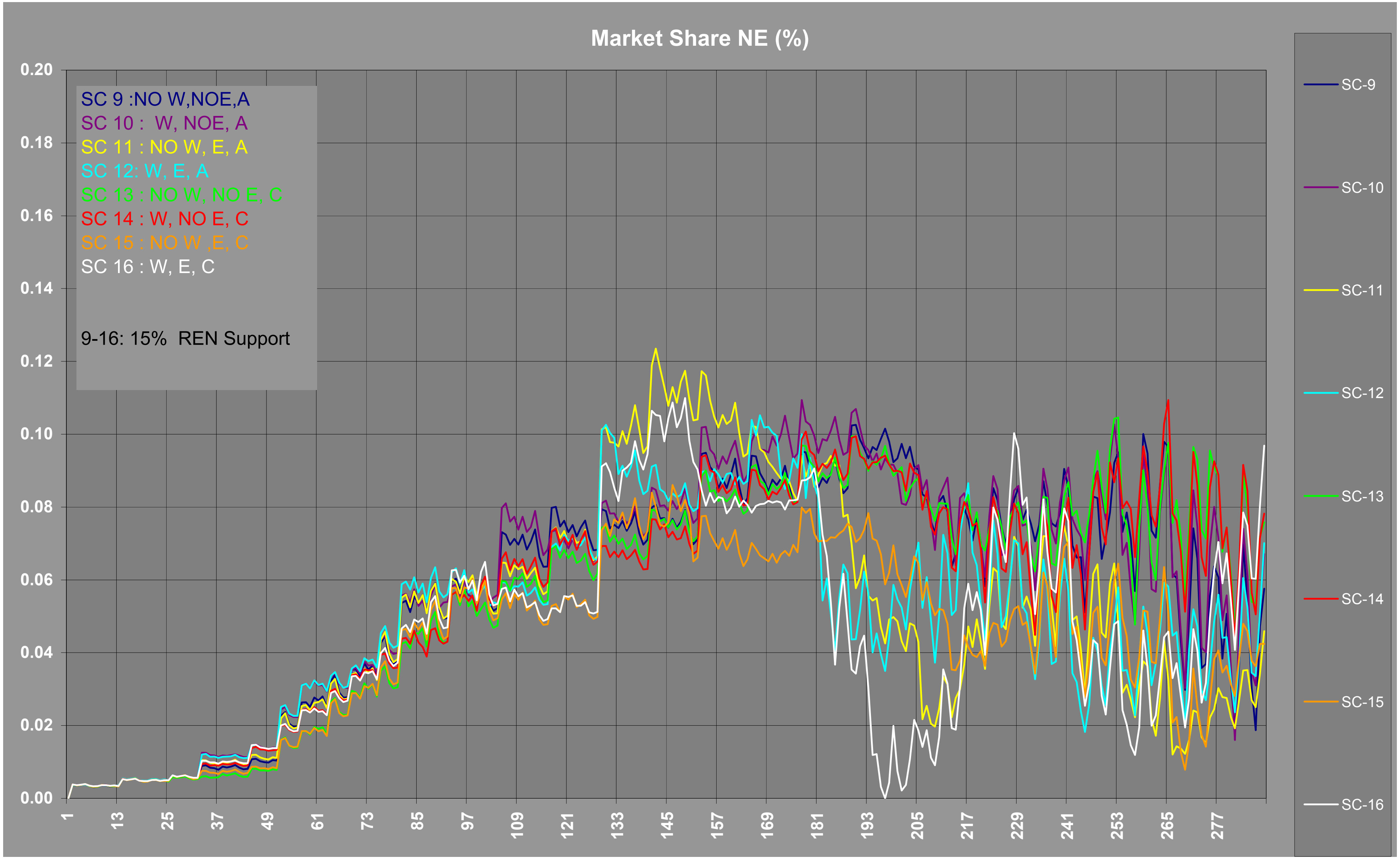
Market Share IPP ($)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



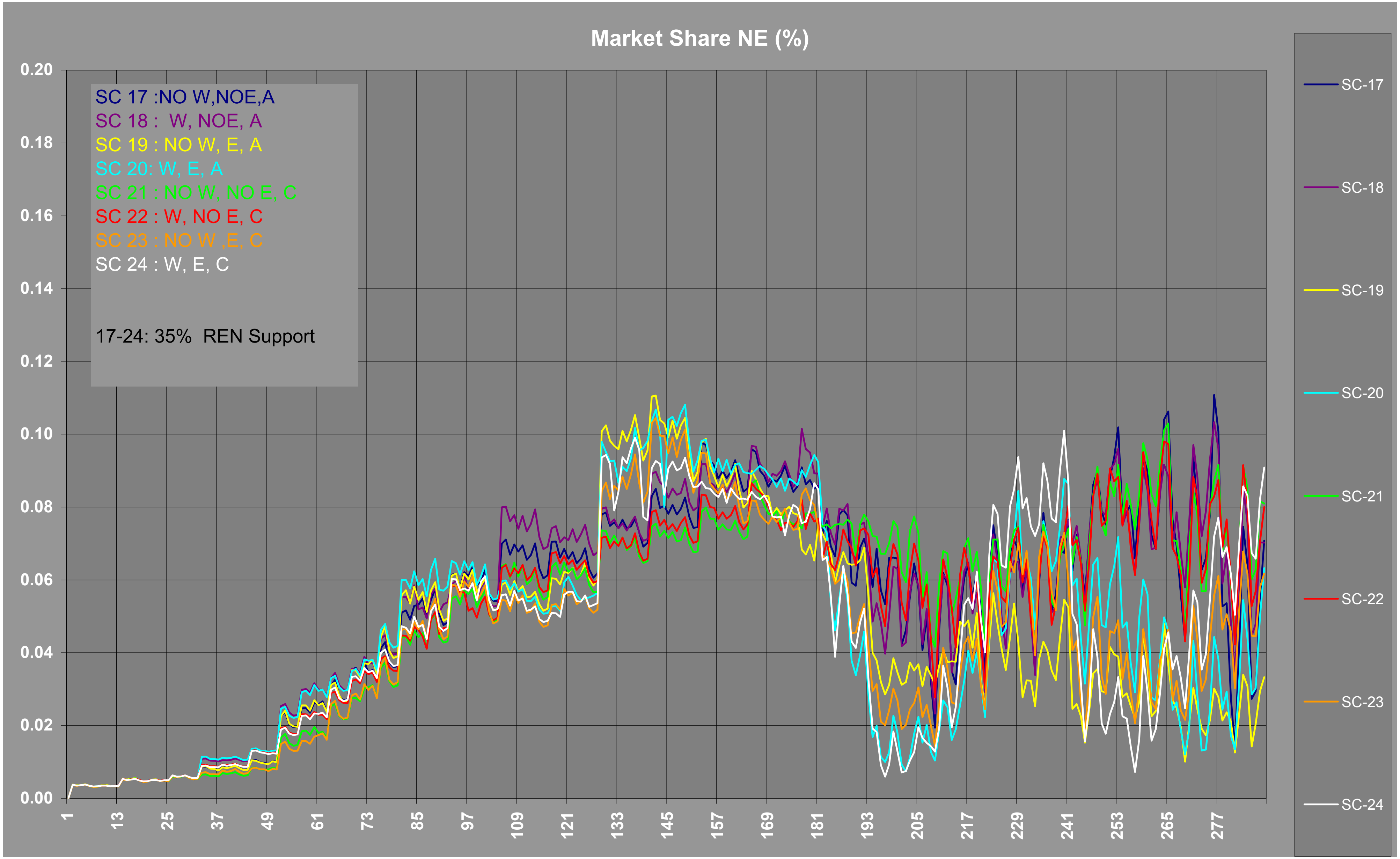
Market Share IPP ($)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
0.35
0.30
0.25
0.20
0.15
0.10
0.05
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



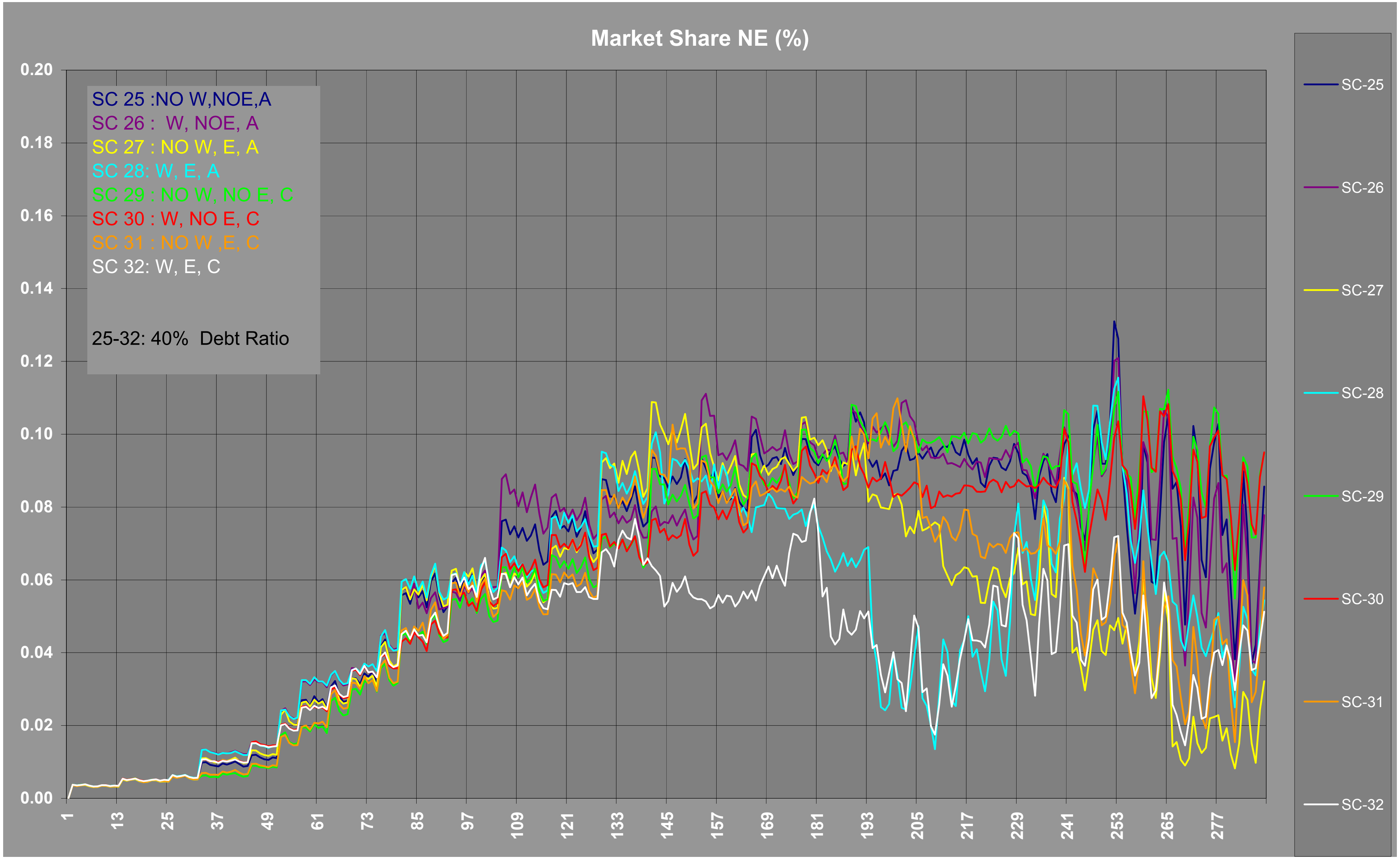
Market Share NE (%)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Market Share NE (%)
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



Market Share NE (%)
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24


Market Share NE (%)
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
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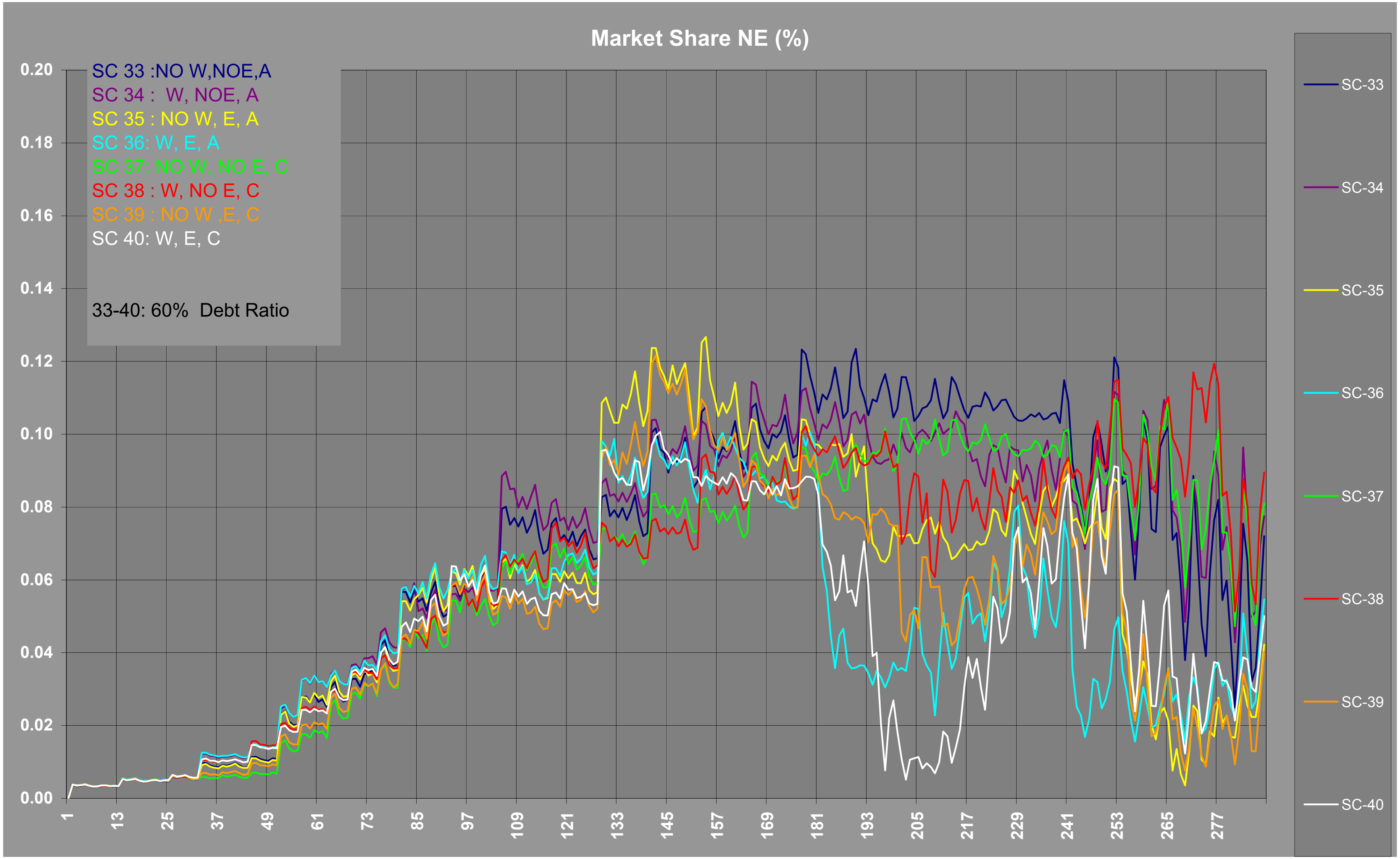
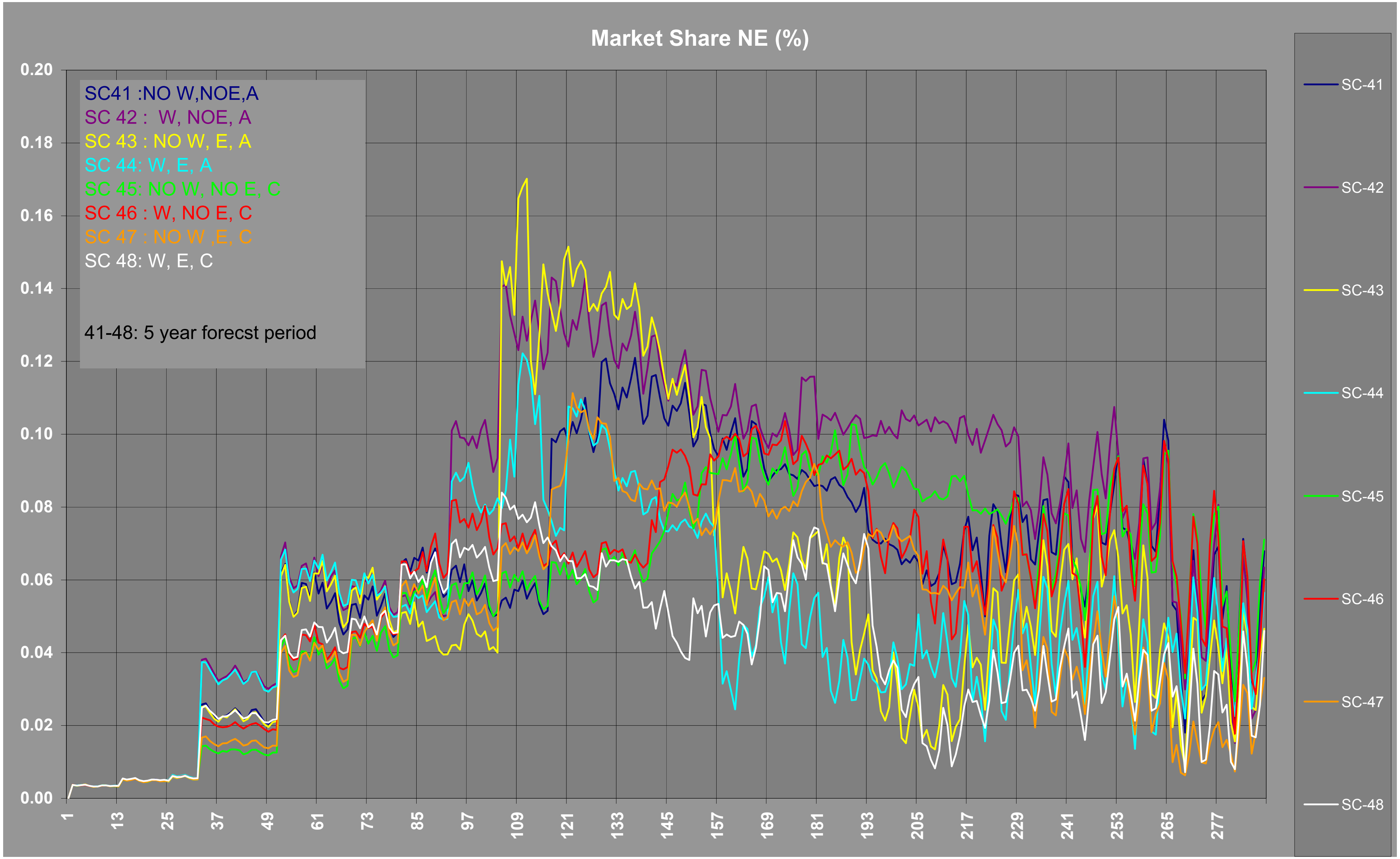
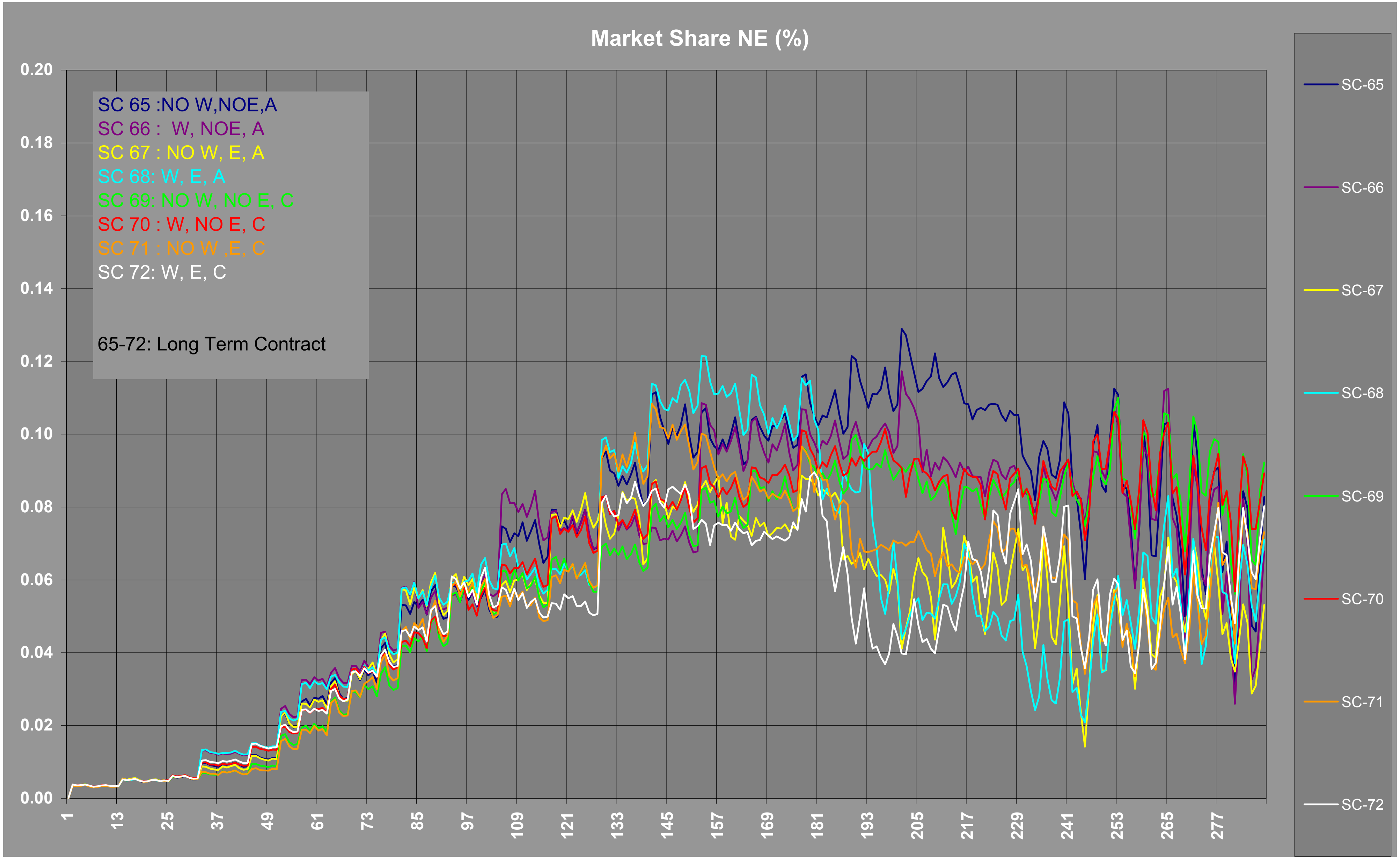
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32

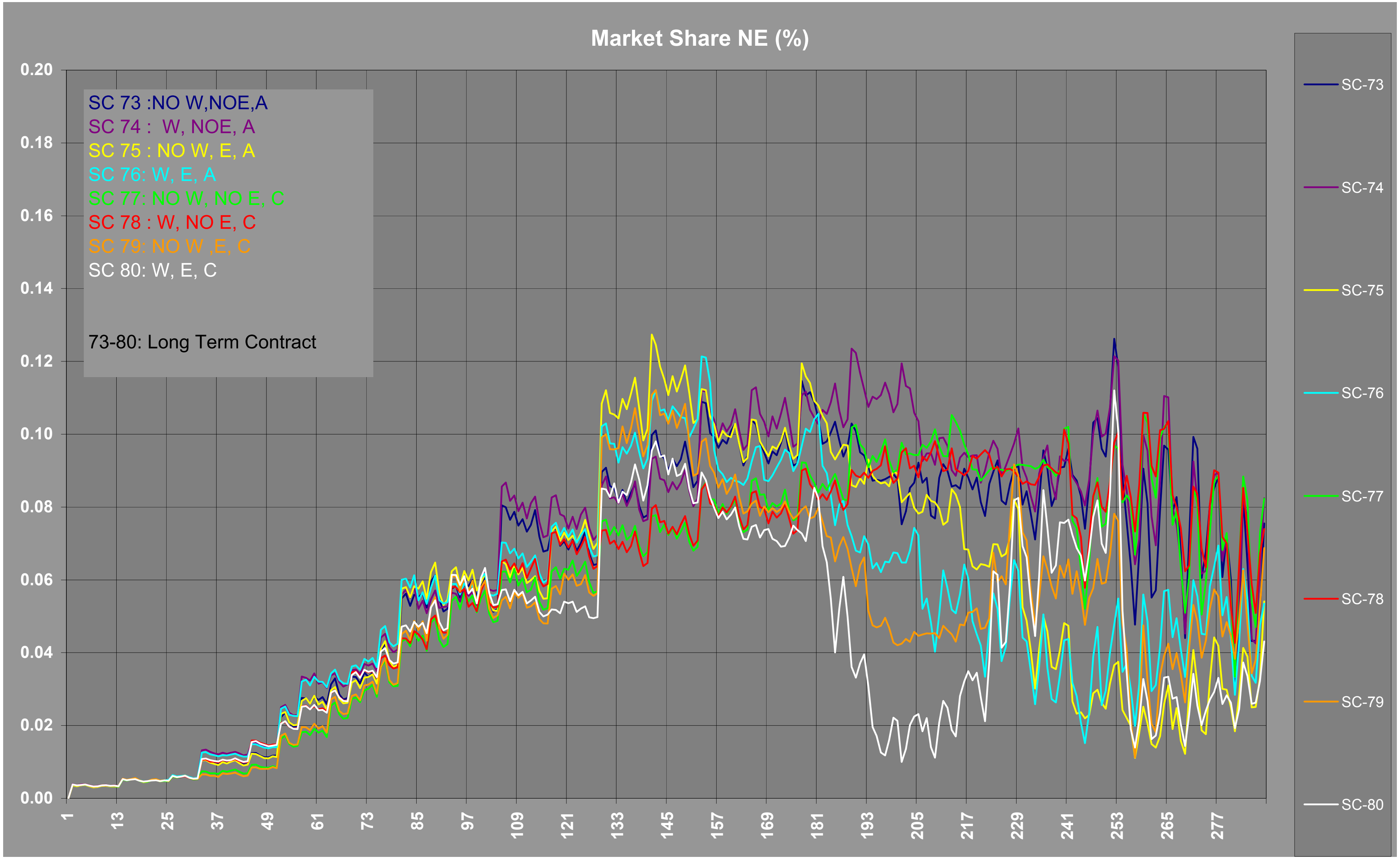


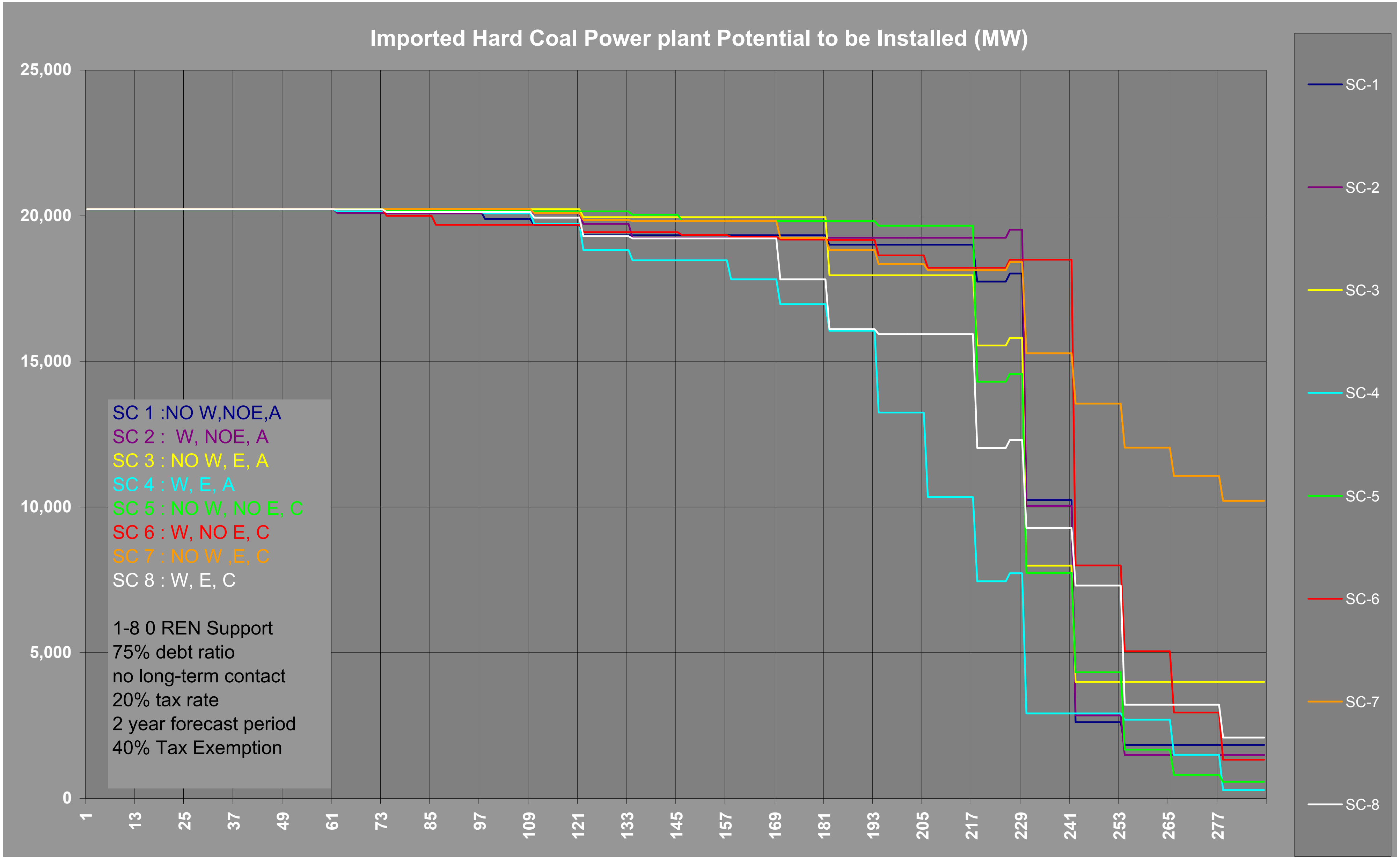
Market Share NE (%)
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



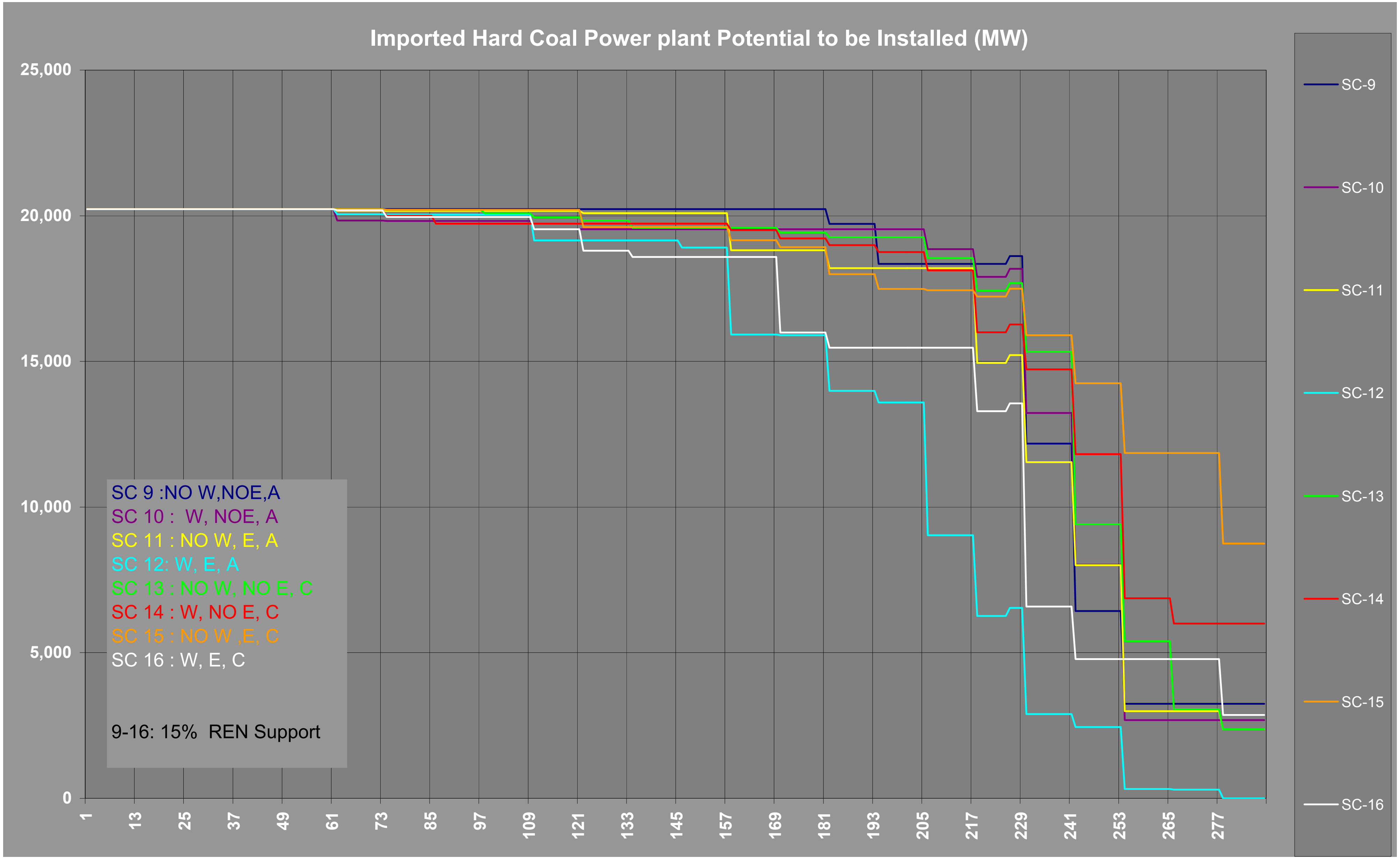
Market Share NE (%)
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48


Market Share NE (%)
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72

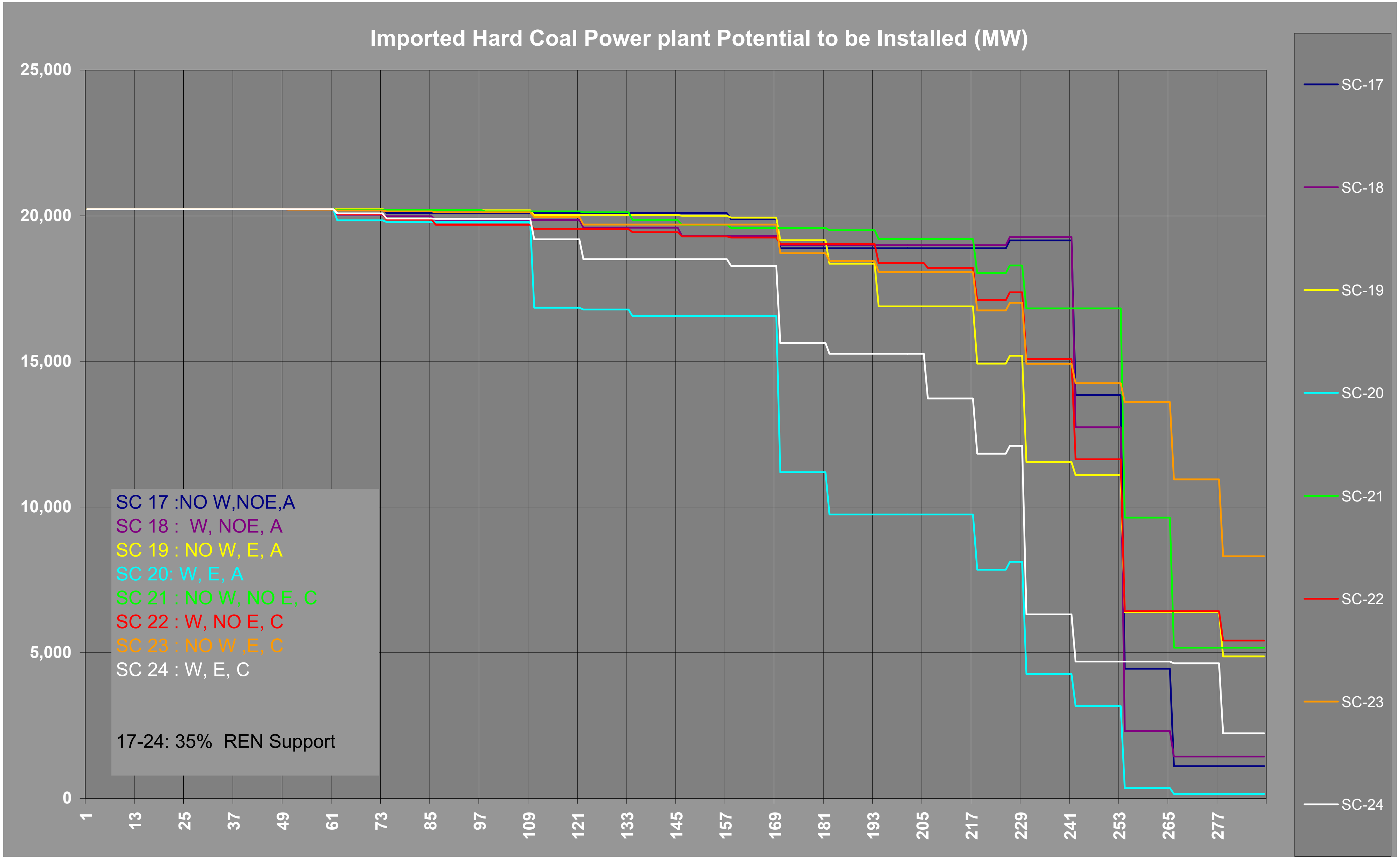

Market Share NE (%)
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: Long Term Contract
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80
0.20
0.18
0.16
0.14
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277



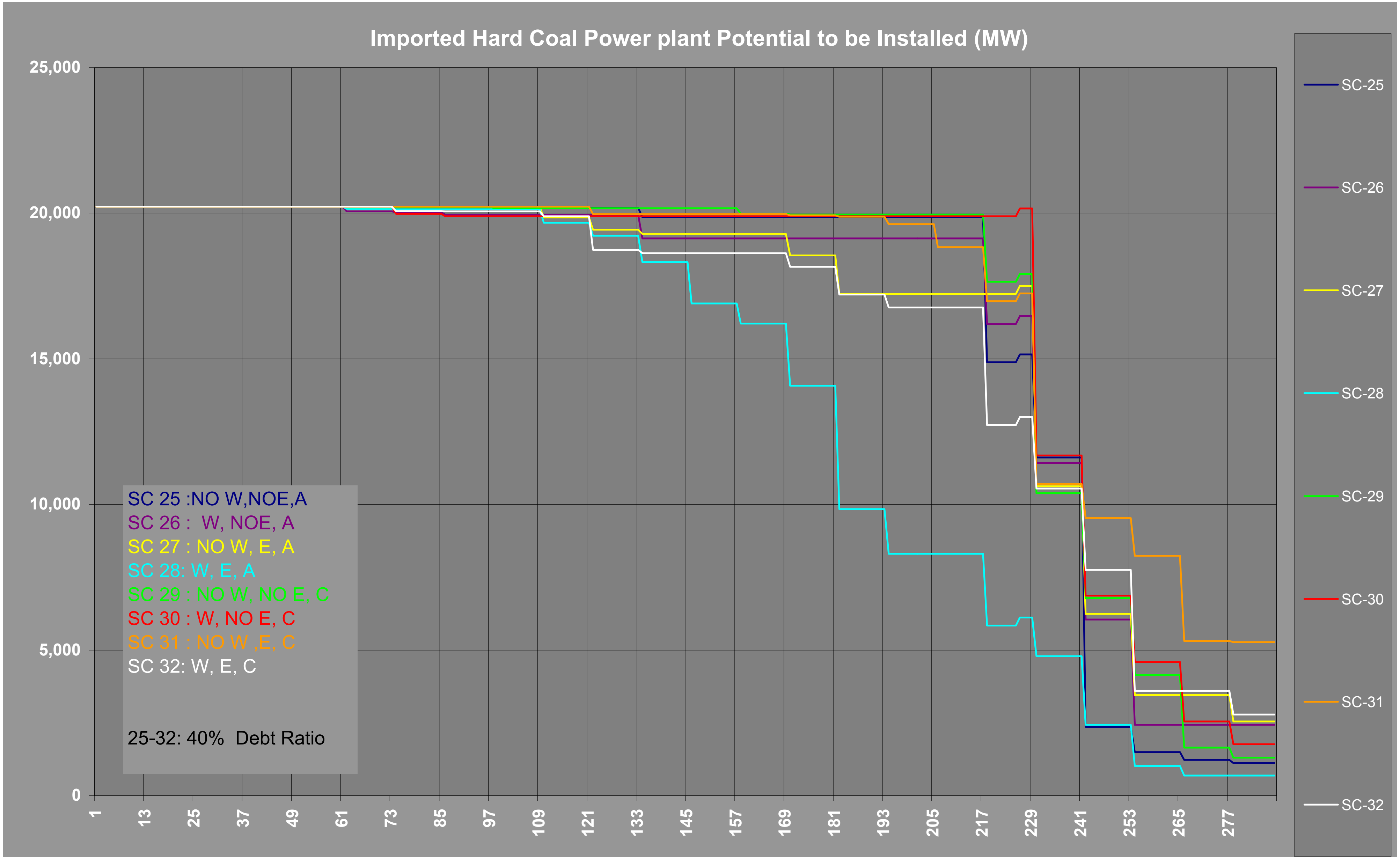
Imported Hard Coal Power plant Potential to be Installed (MW)
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption



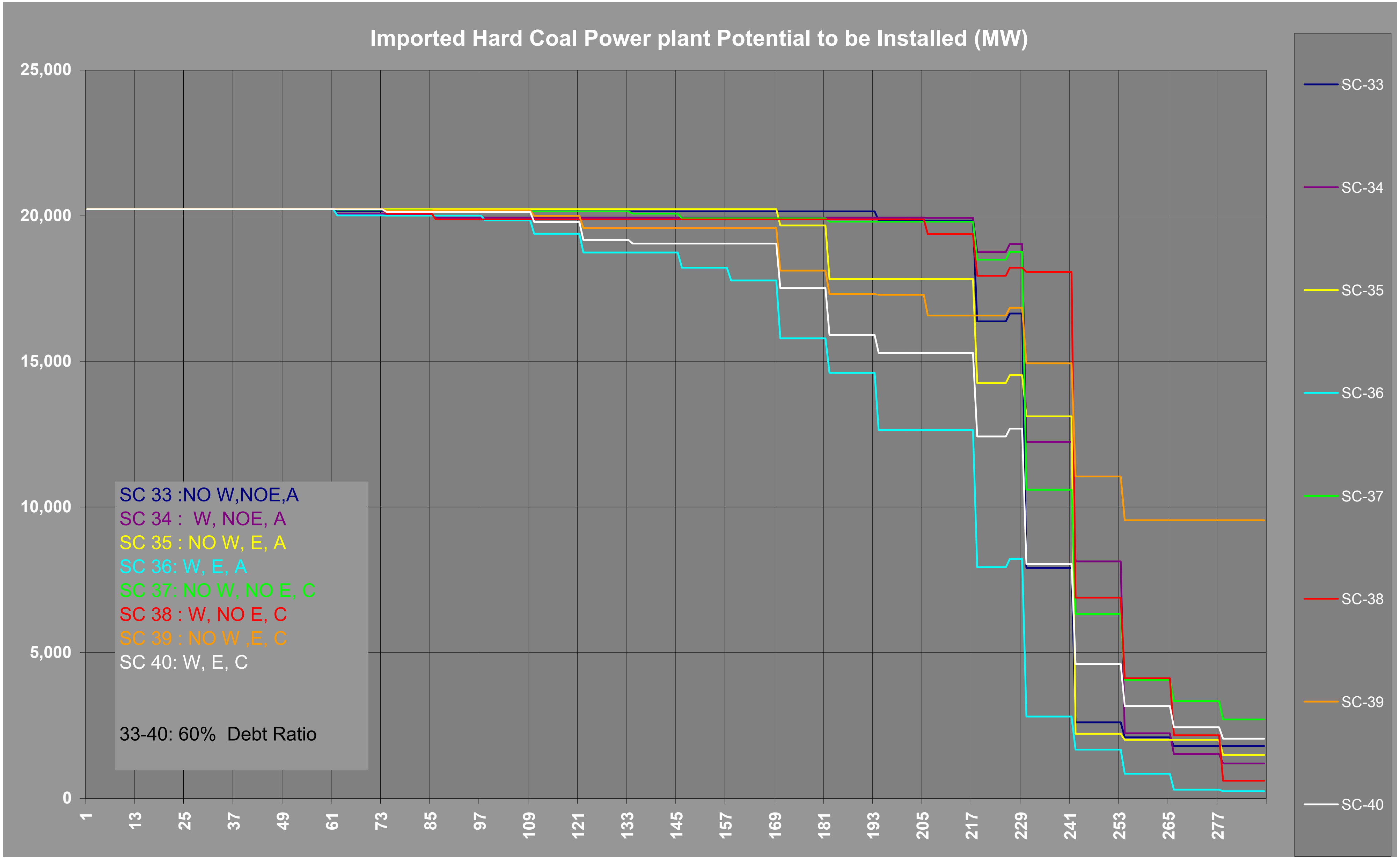
Imported Hard Coal Power plant Potential to be Installed (MW)
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support



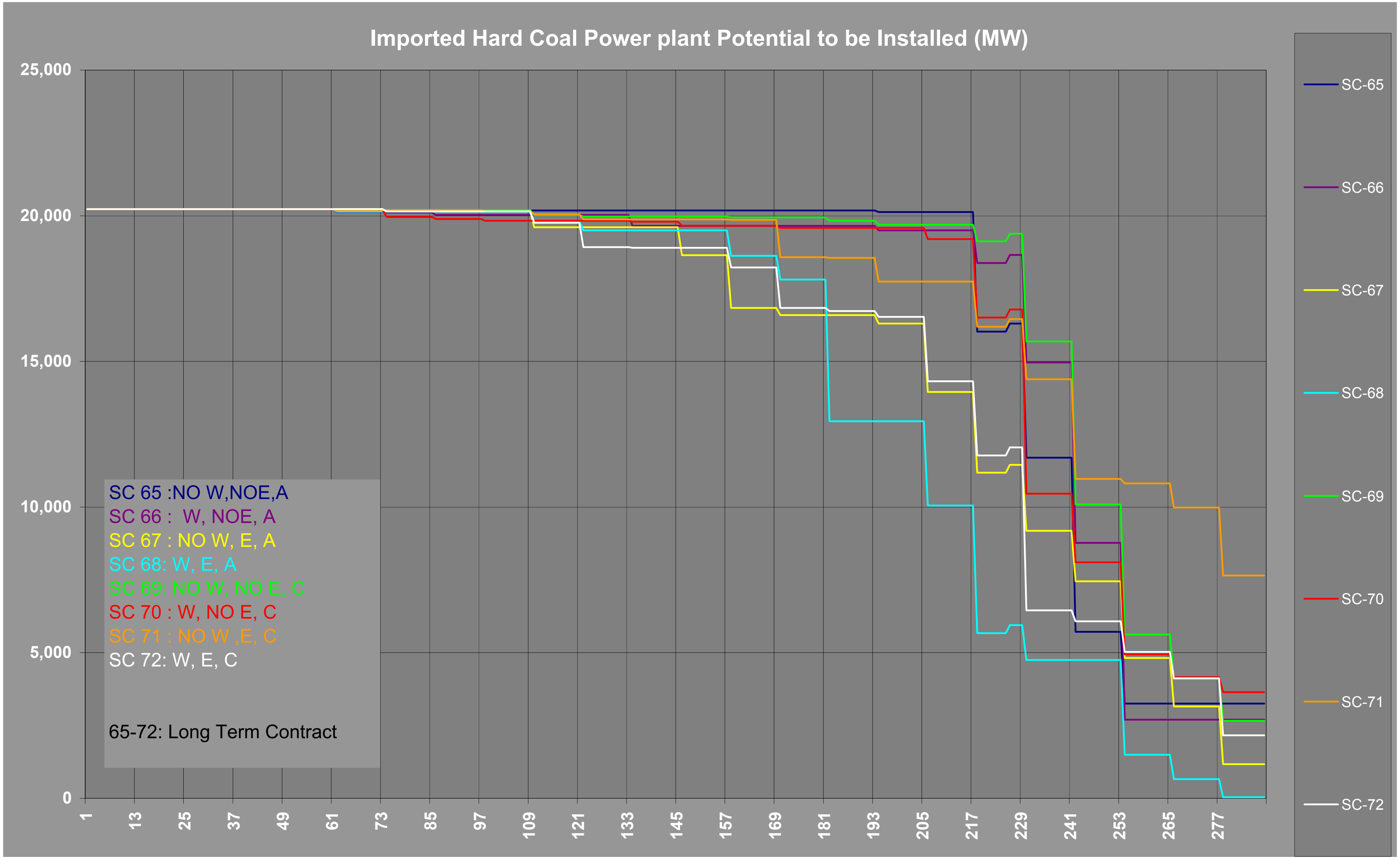
Imported Hard Coal Power plant Potential to be Installed (MW)
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support



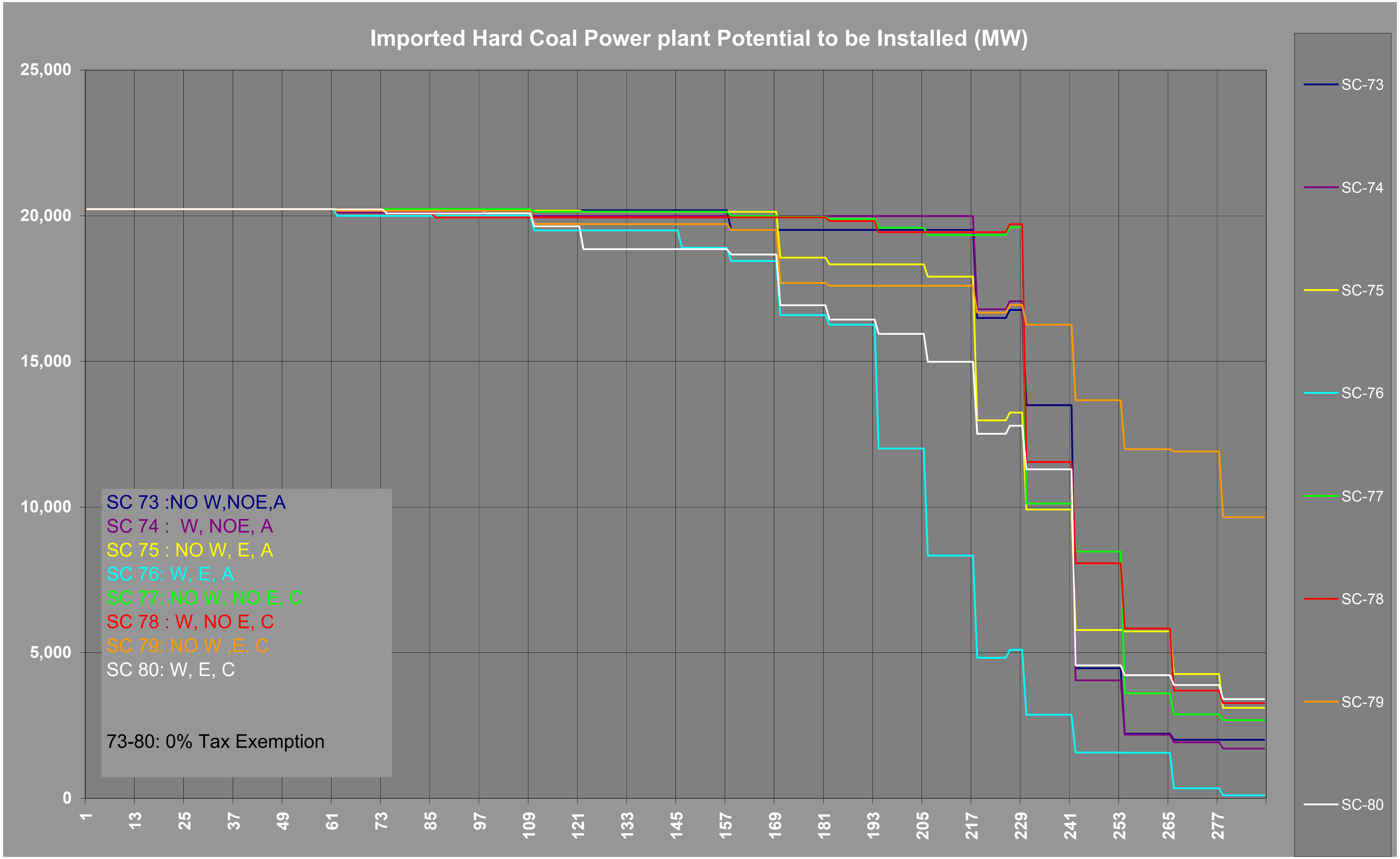
Imported Hard Coal Power plant Potential to be Installed (MW)
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32


Imported Hard Coal Power plant Potential to be Installed (MW)
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

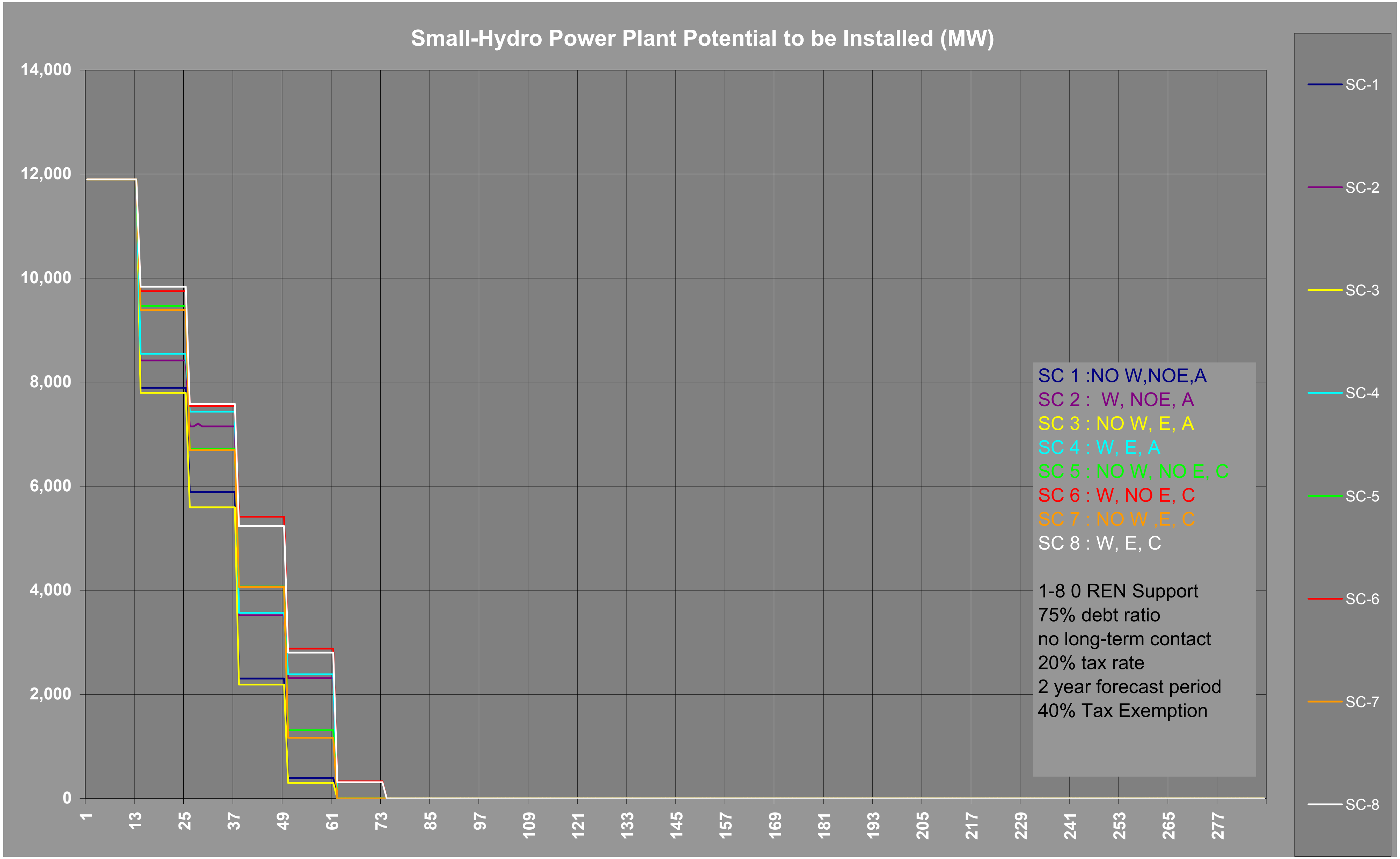
Imported Hard Coal Power plant Potential to be Installed (MW)
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



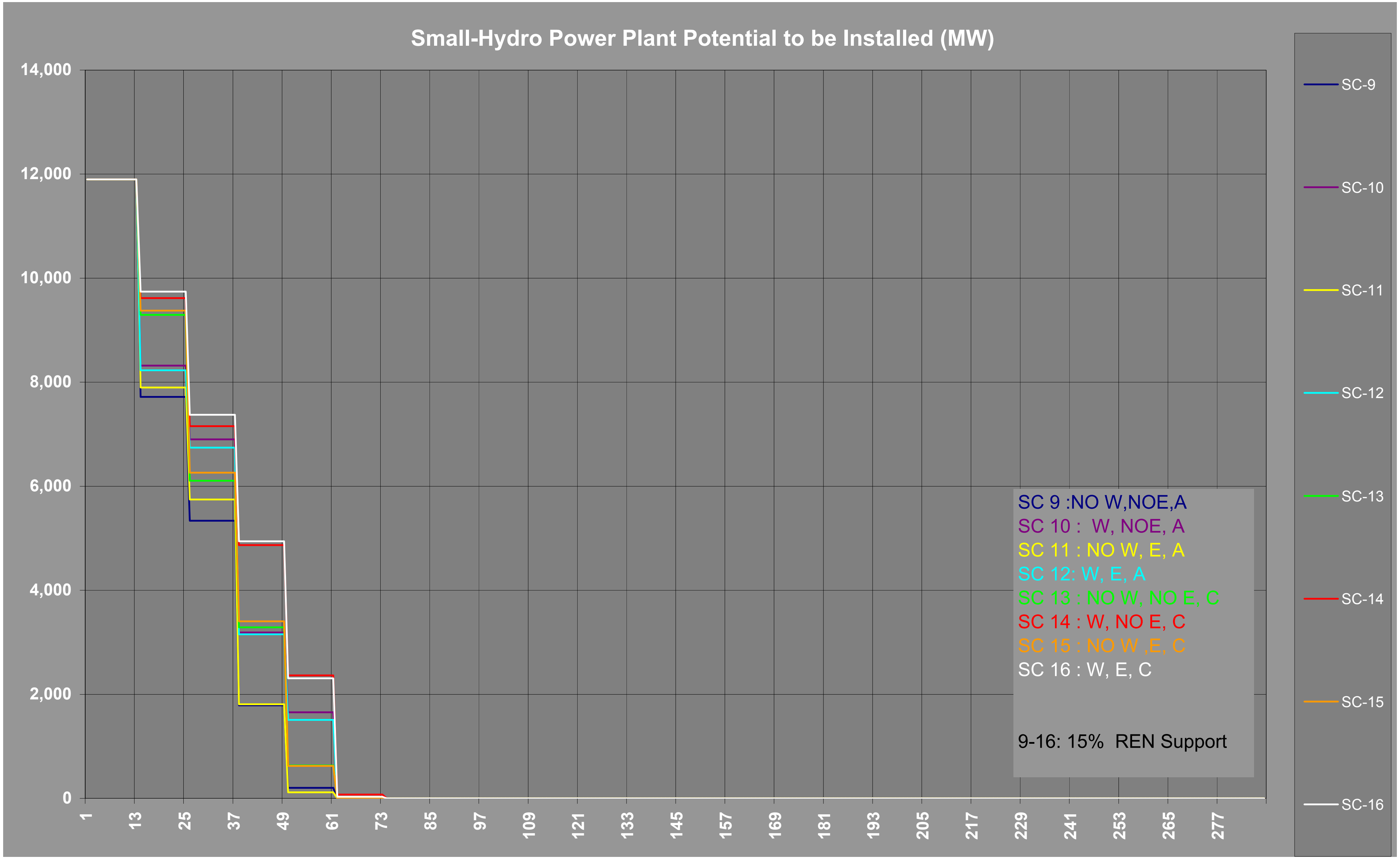
Imported Hard Coal Power plant Potential to be Installed (MW)
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



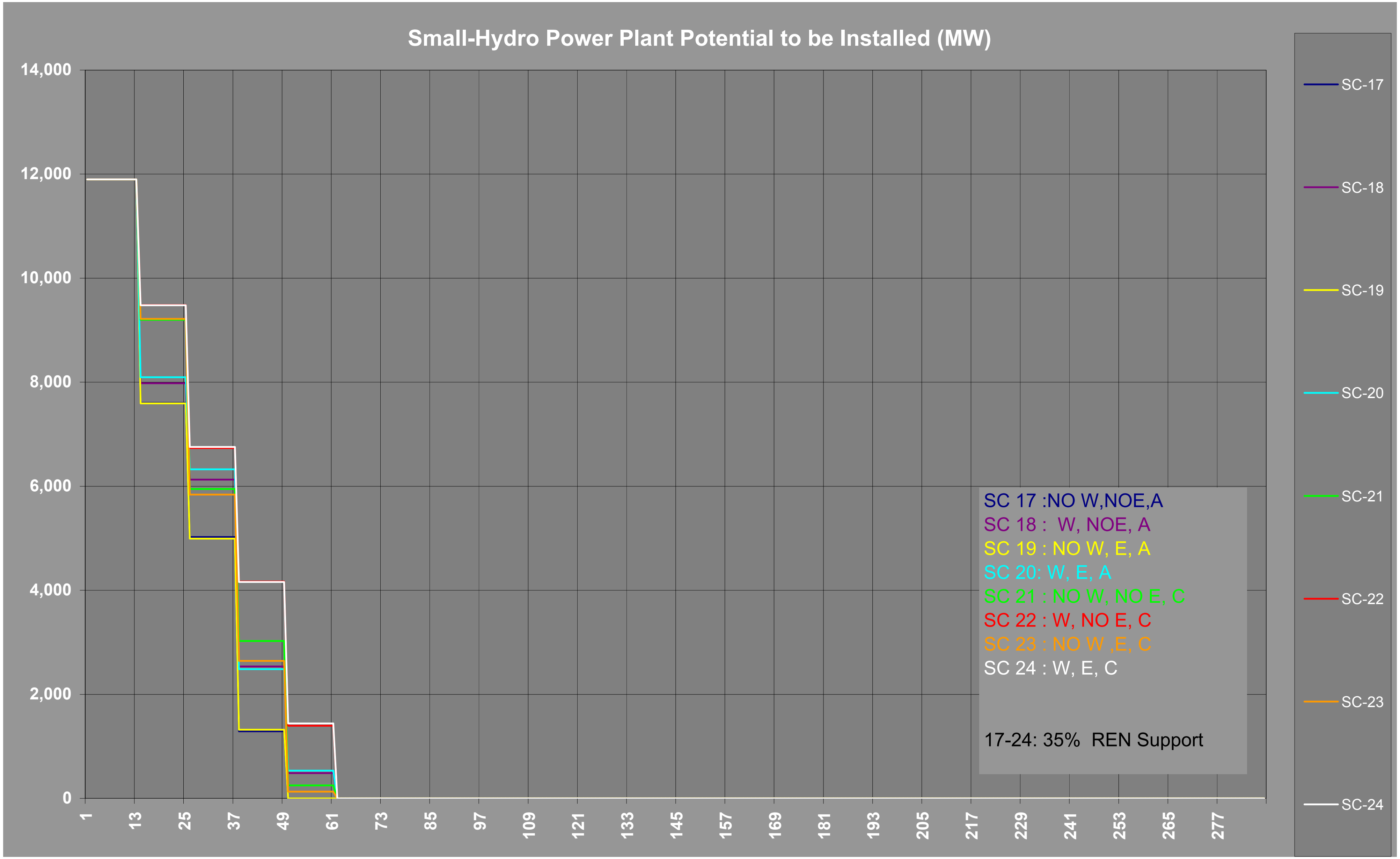
Imported Hard Coal Power plant Potential to be Installed (MW)
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



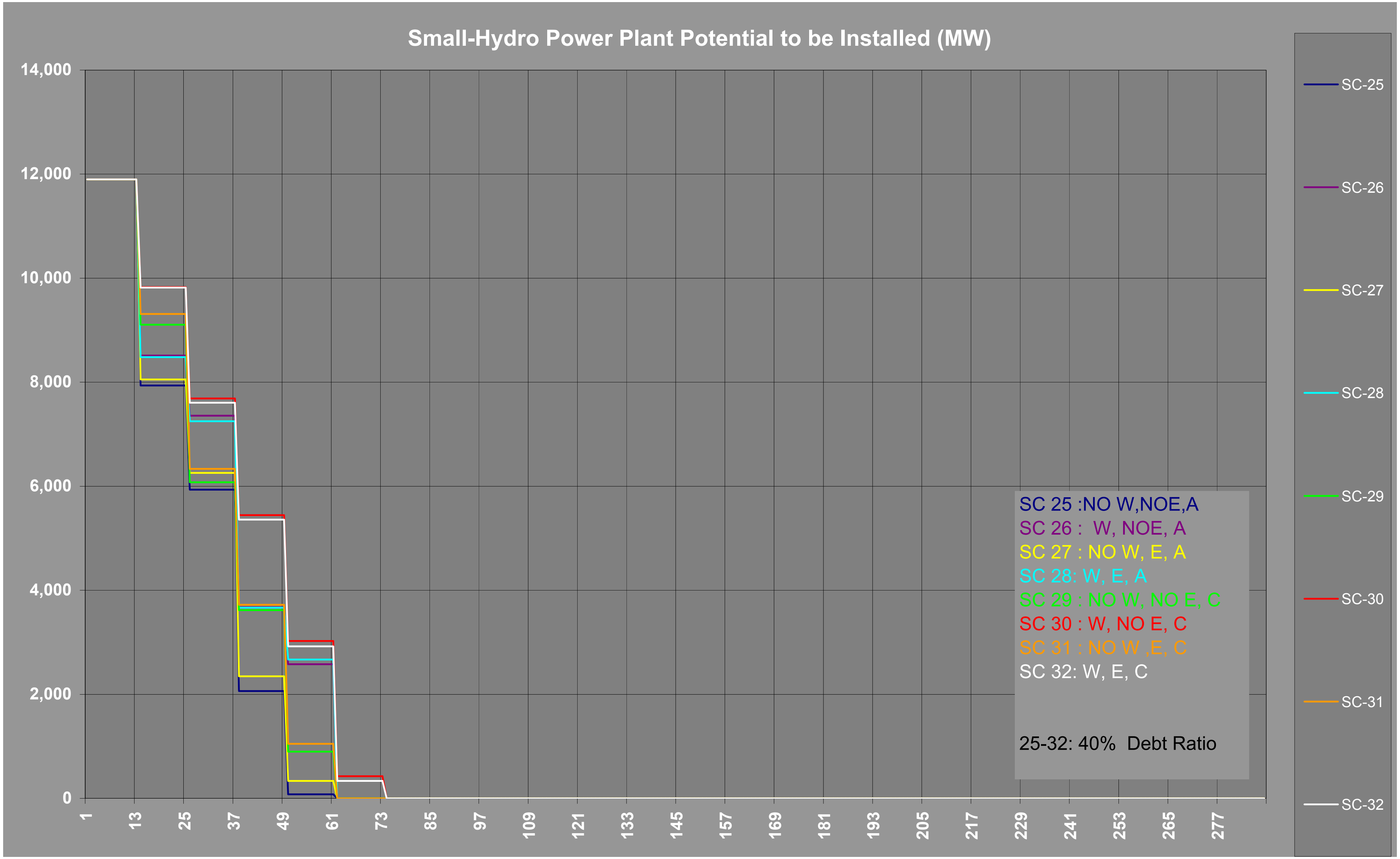
Small-Hydro Power Plant Potential to be Installed (MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



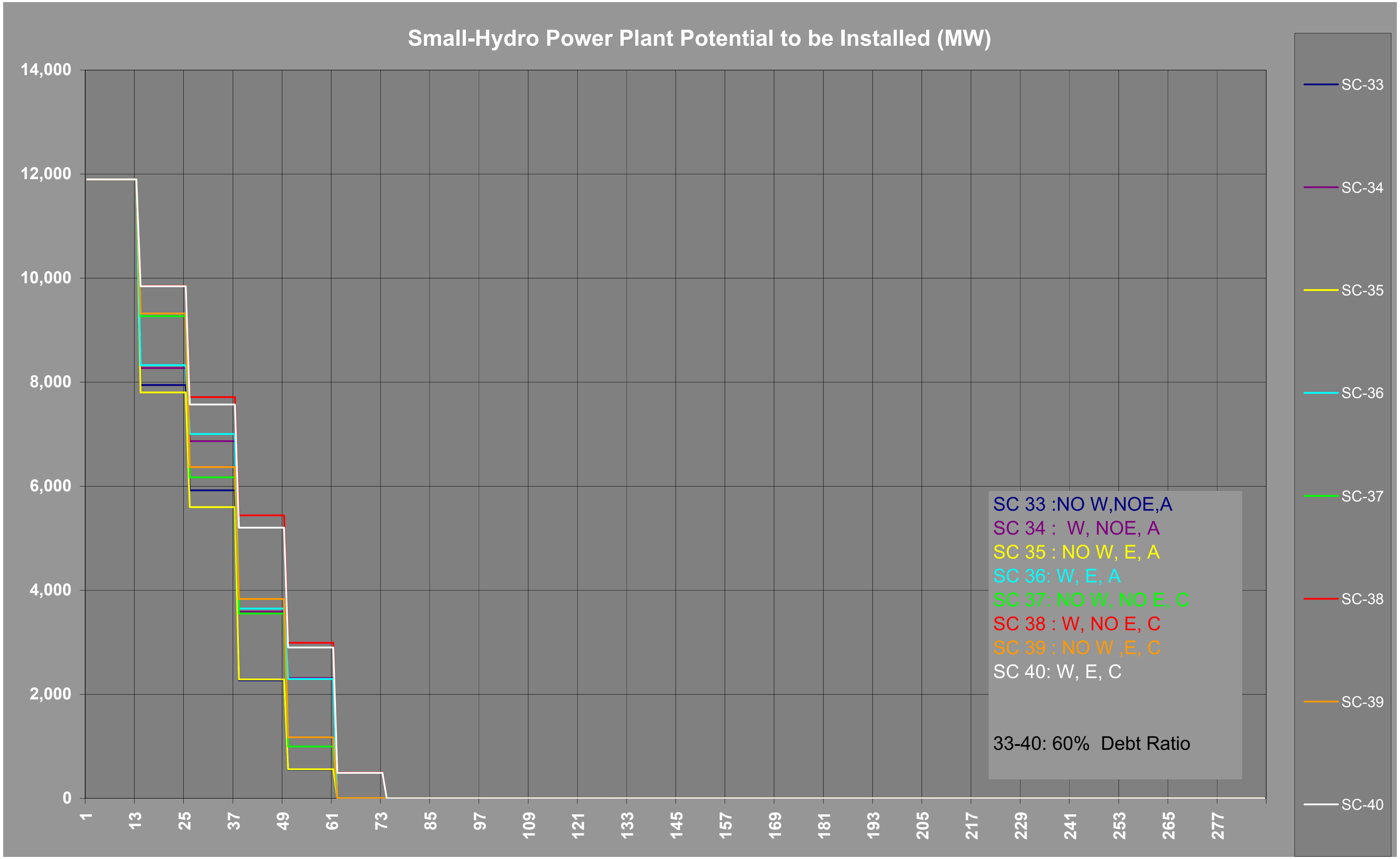
Small-Hydro Power Plant Potential to be Installed (MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support



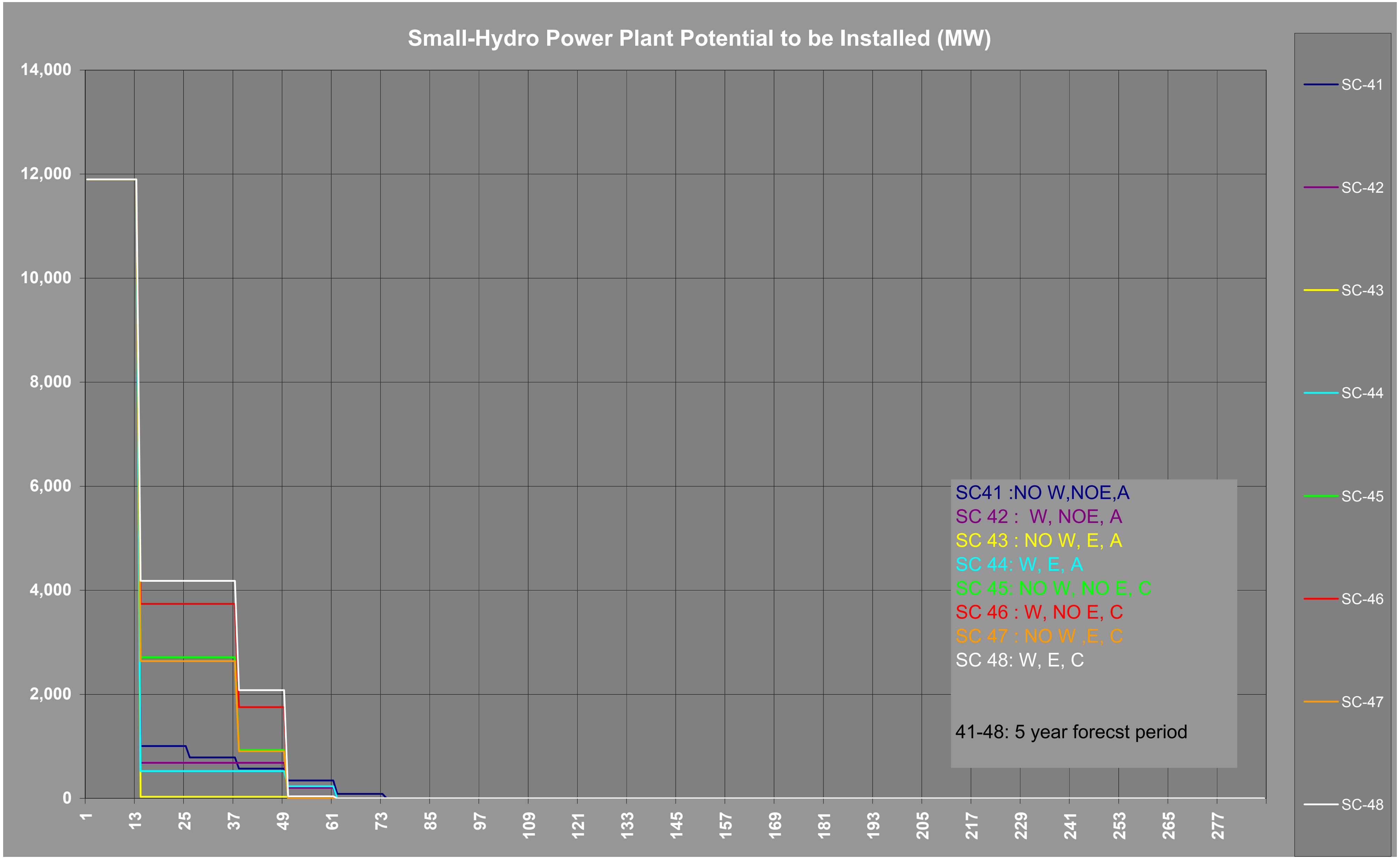
Small-Hydro Power Plant Potential to be Installed (MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support



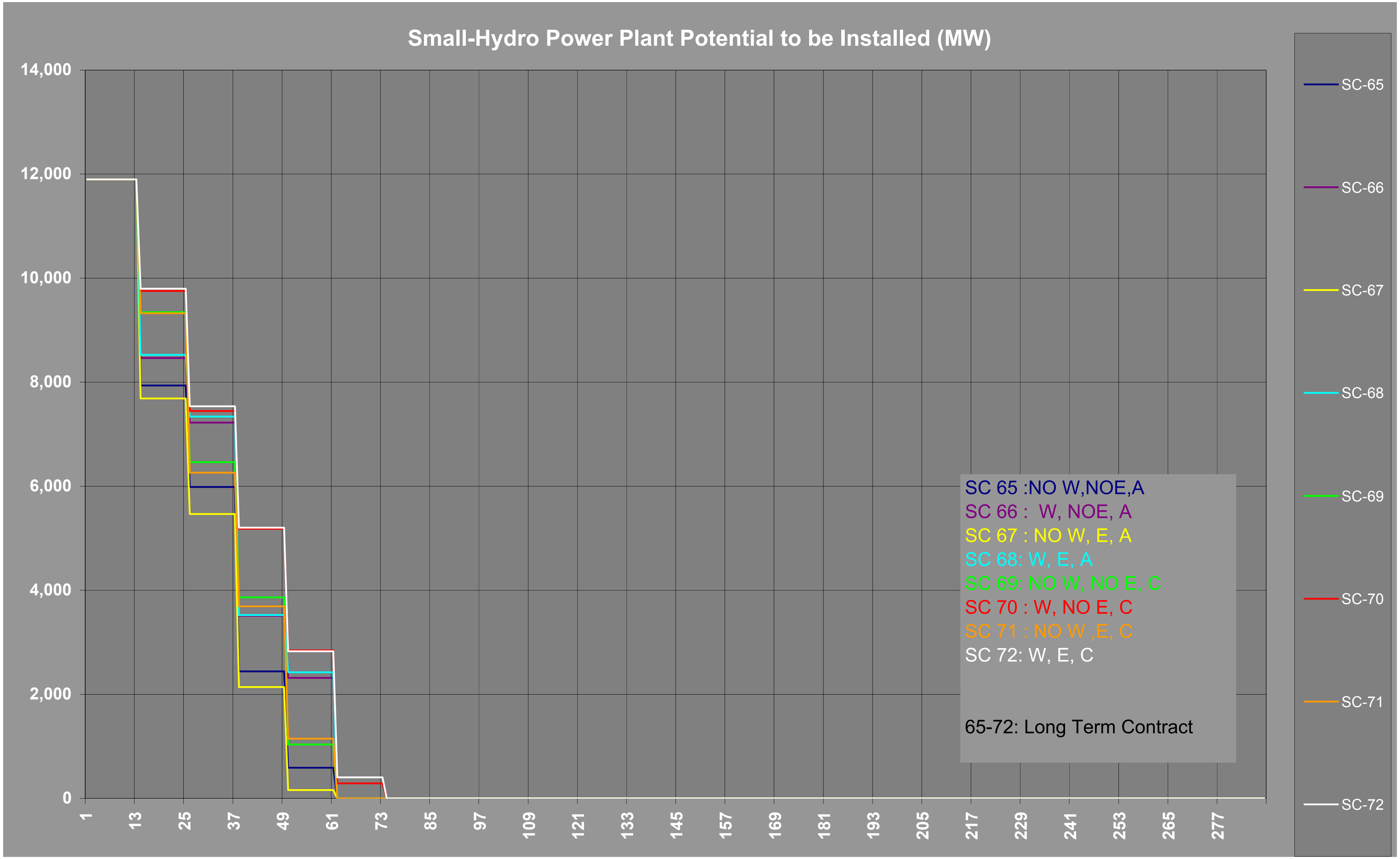
Small-Hydro Power Plant Potential to be Installed (MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



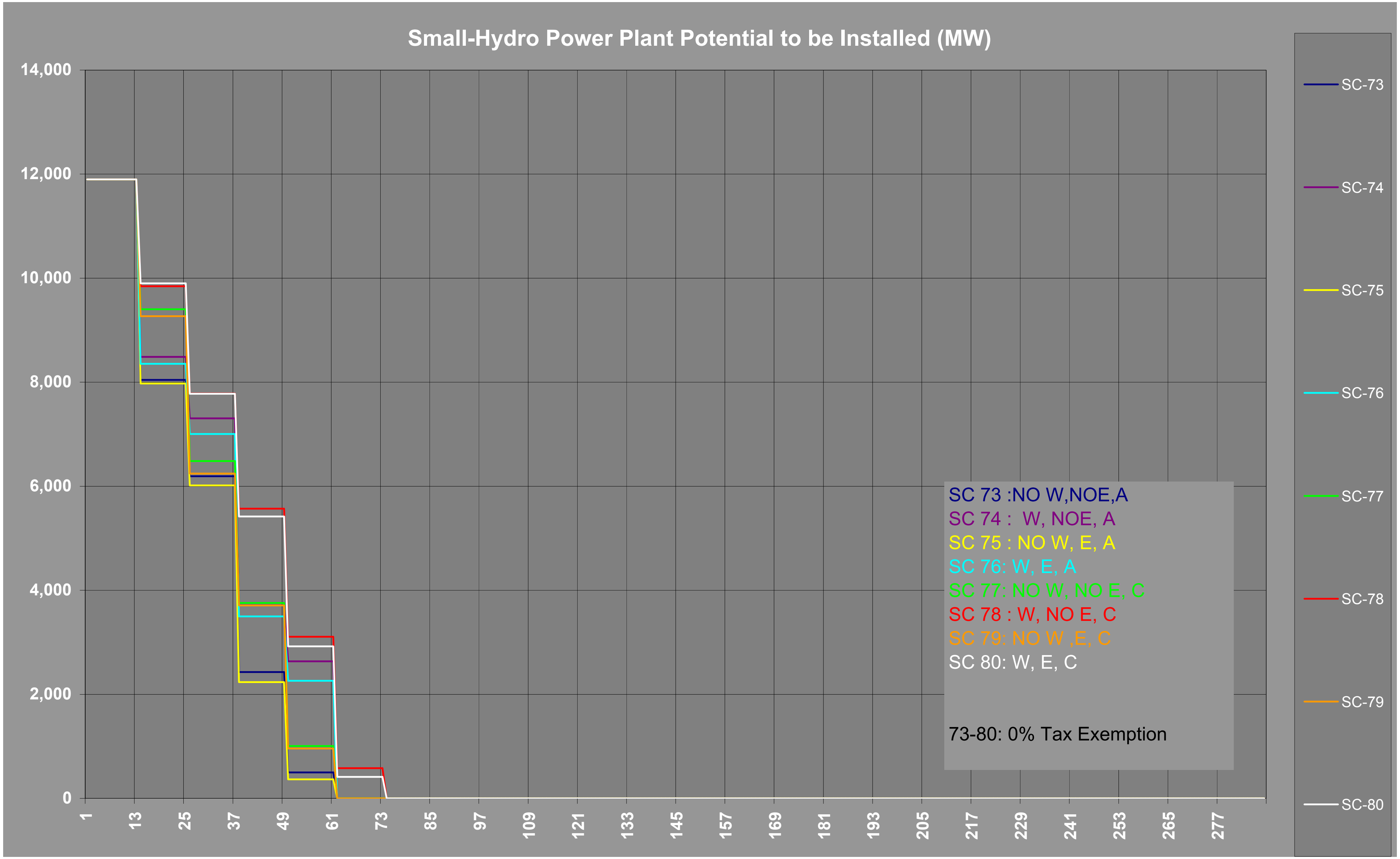
Small-Hydro Power Plant Potential to be Installed (MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio

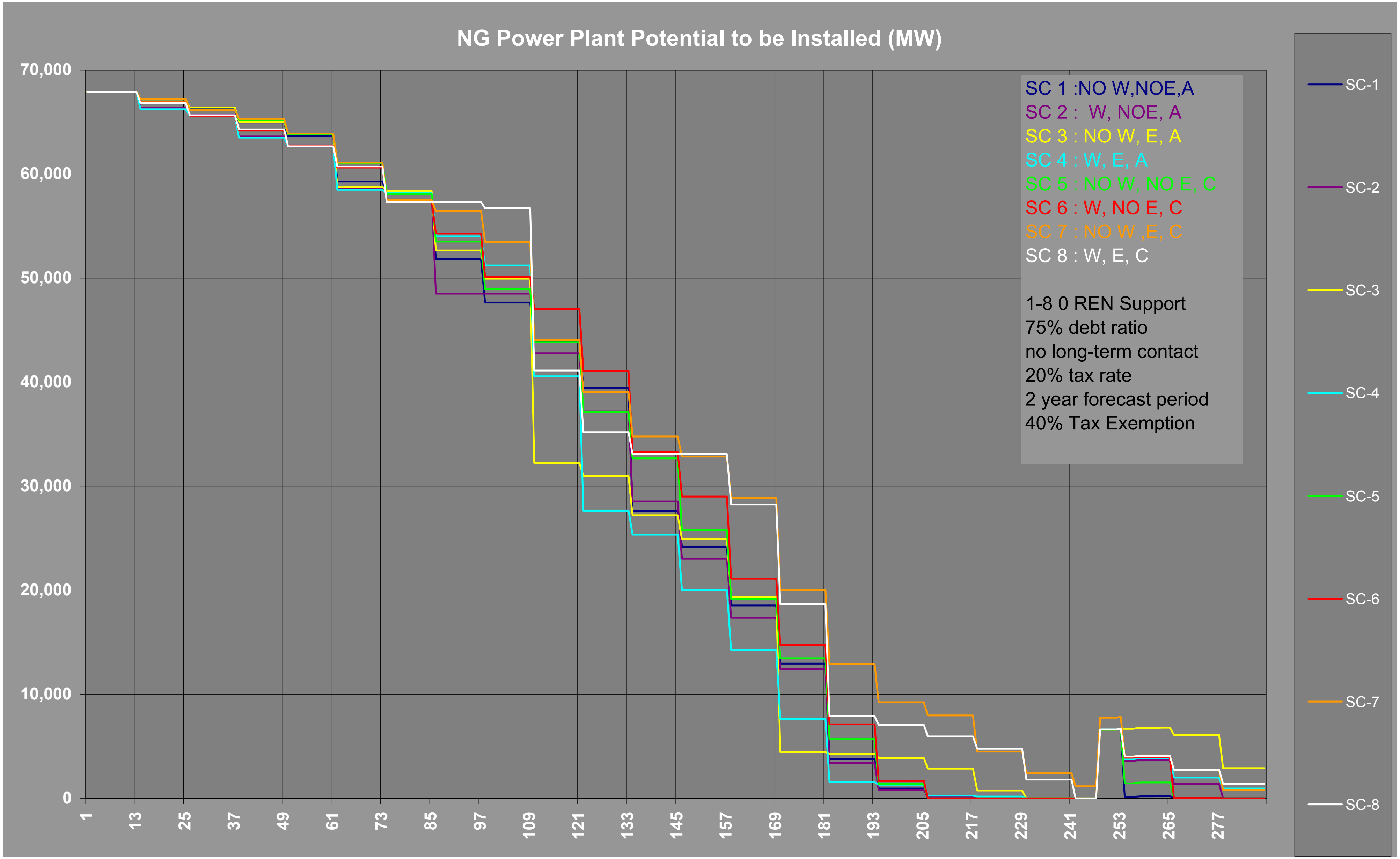


Small-Hydro Power Plant Potential to be Installed (MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period

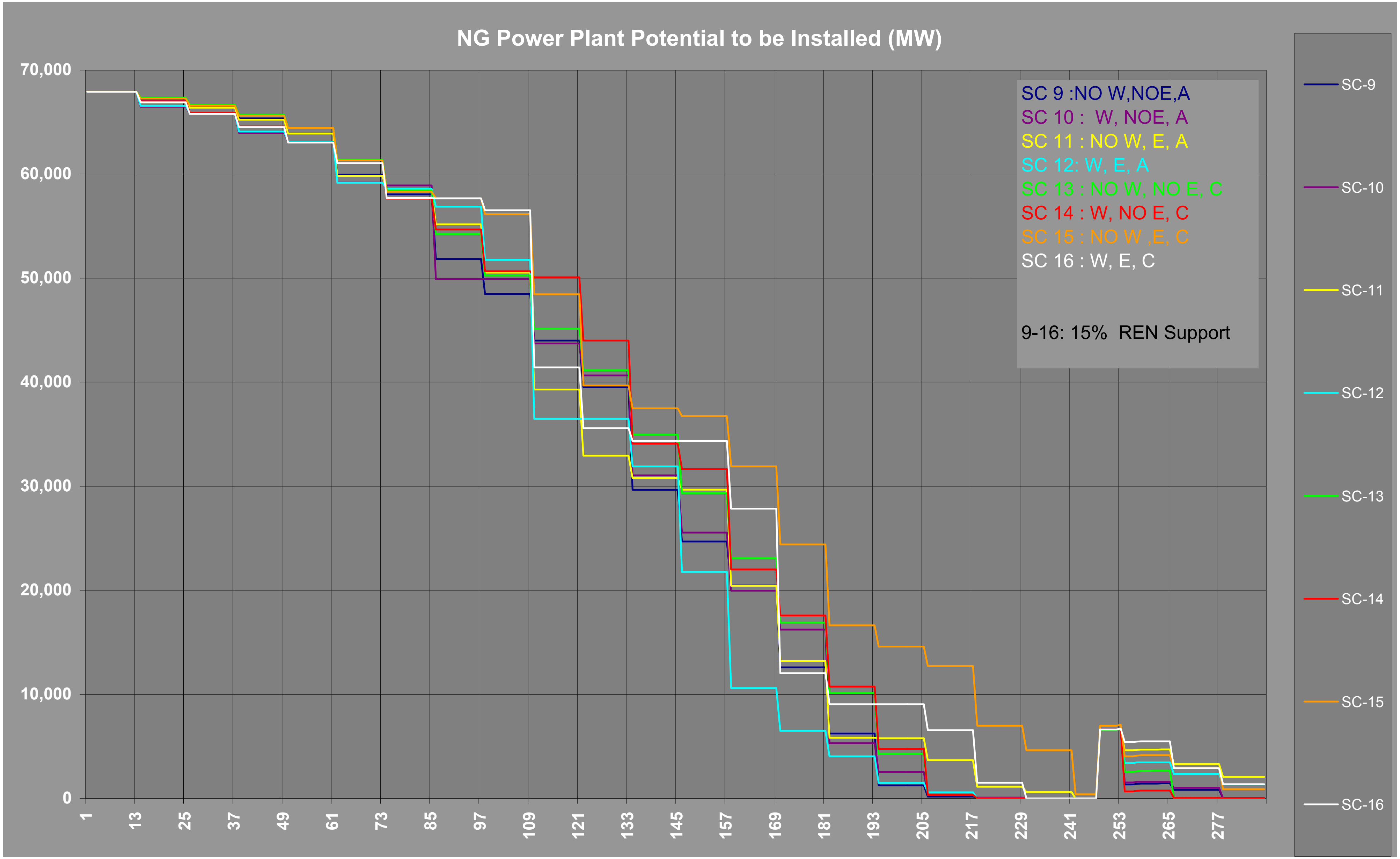


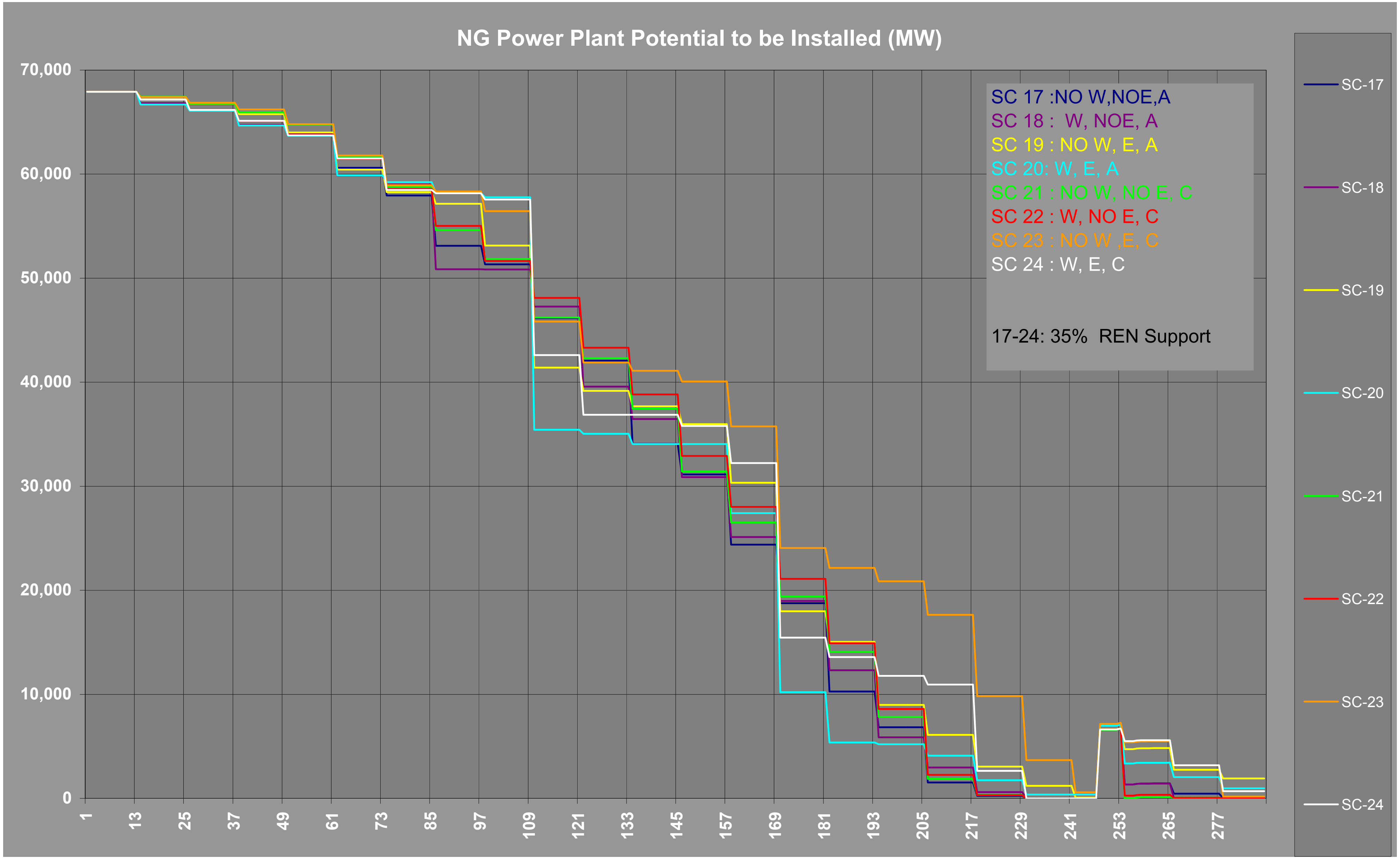
Small-Hydro Power Plant Potential to be Installed (MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72


Small-Hydro Power Plant Potential to be Installed (MW)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

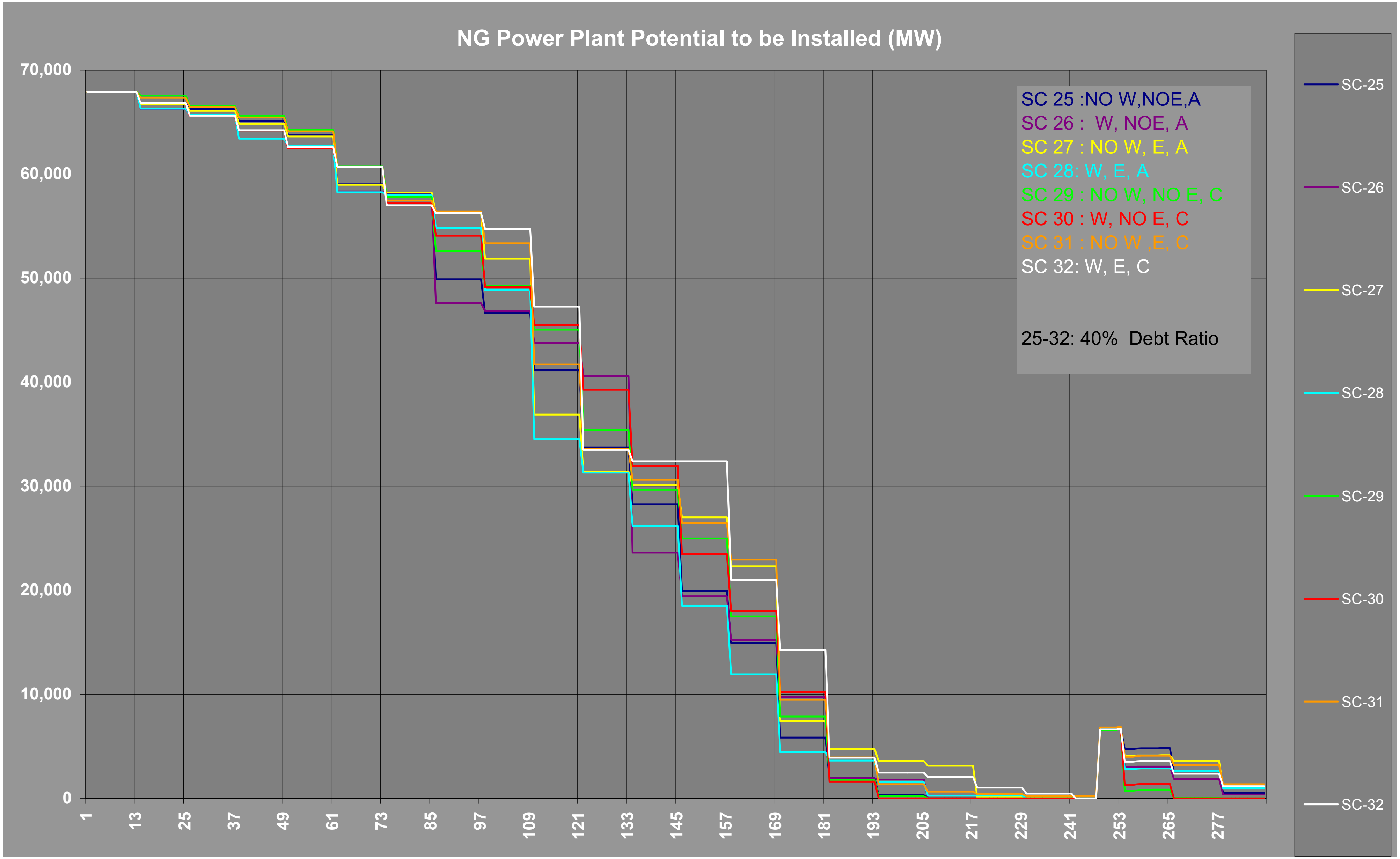


NG Power Plant Potential to be Installed (MW)
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277

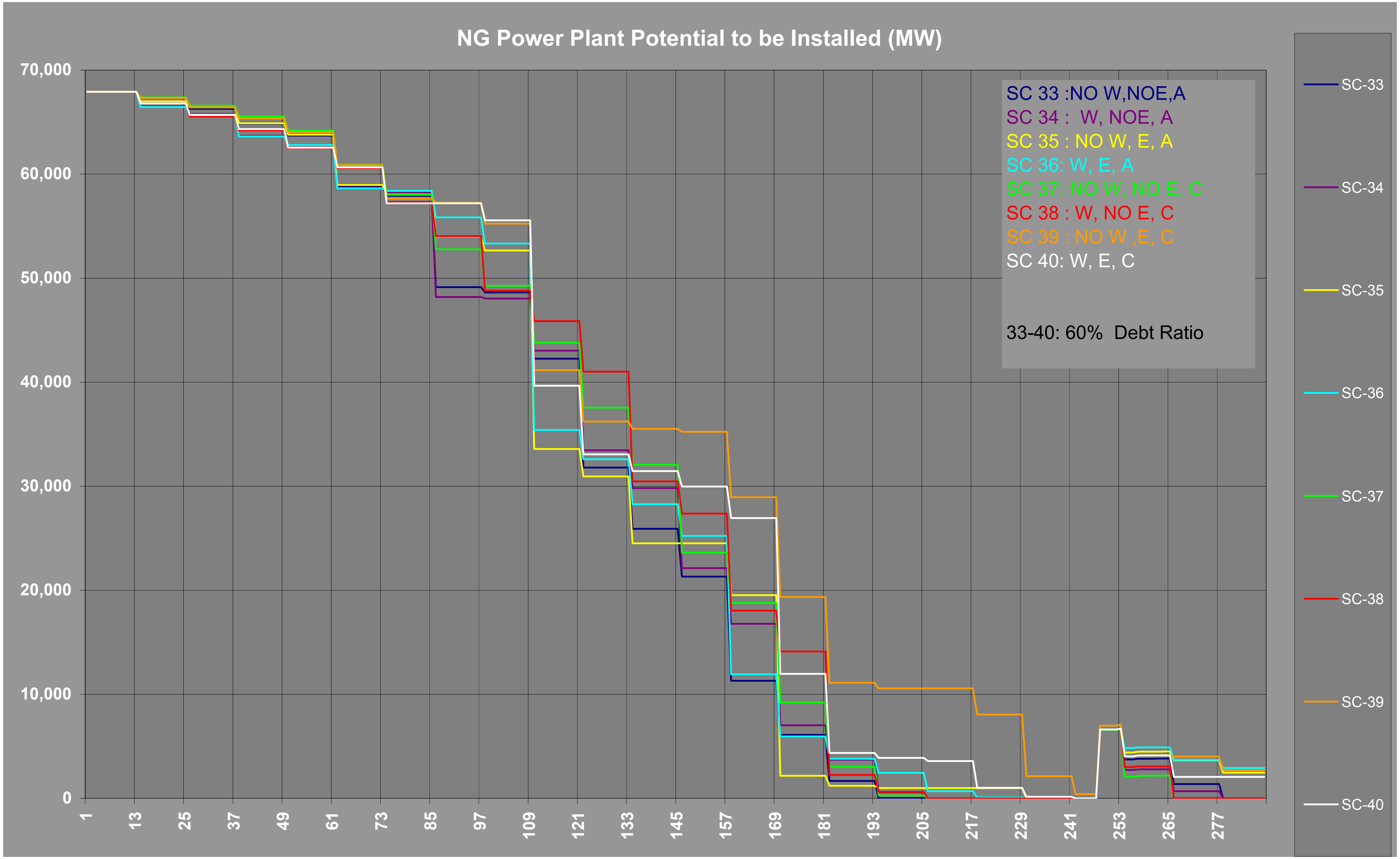

NG Power Plant Potential to be Installed (MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



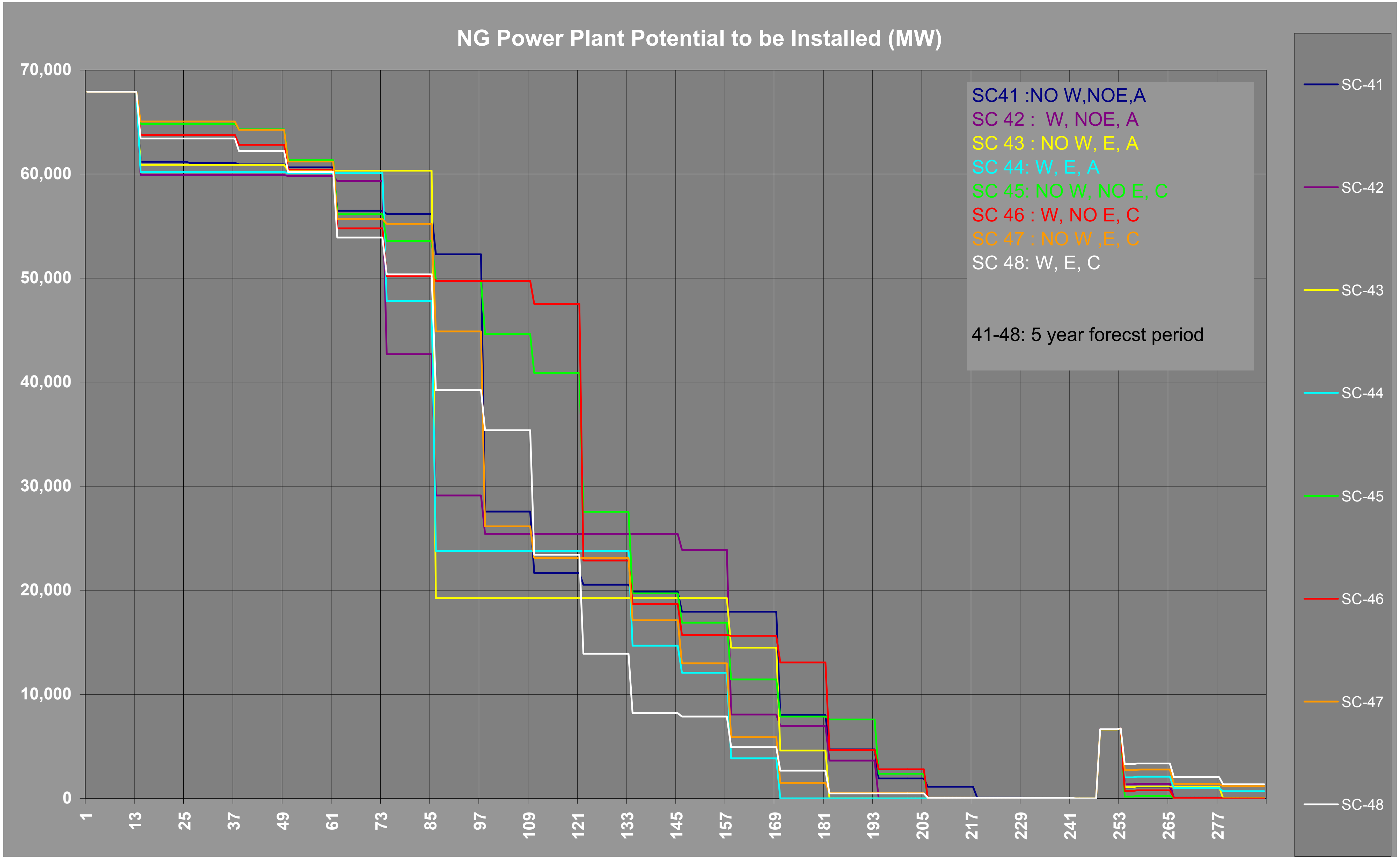
NG Power Plant Potential to be Installed (MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24



NG Power Plant Potential to be Installed (MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



NG Power Plant Potential to be Installed (MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



NG Power Plant Potential to be Installed (MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1
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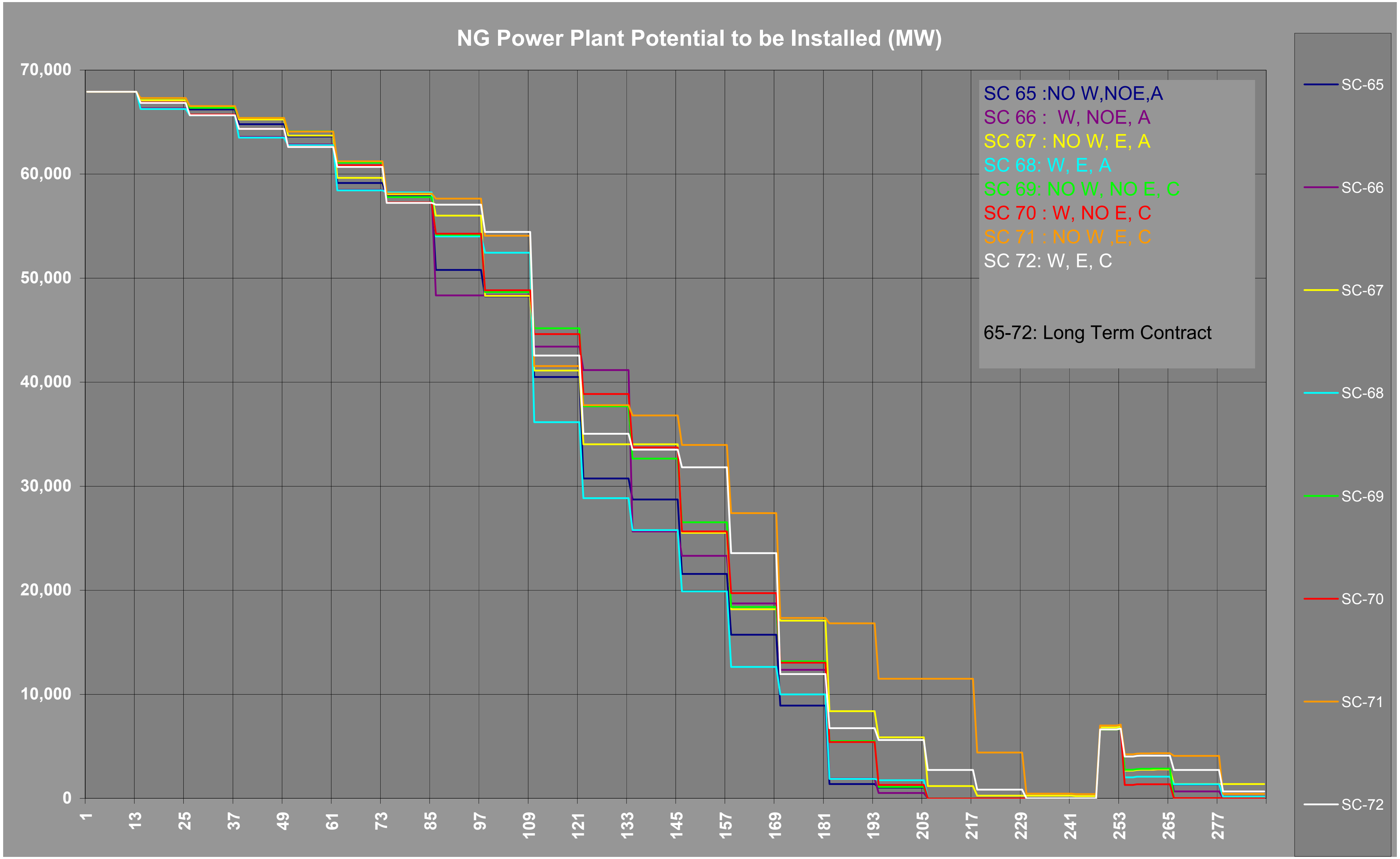
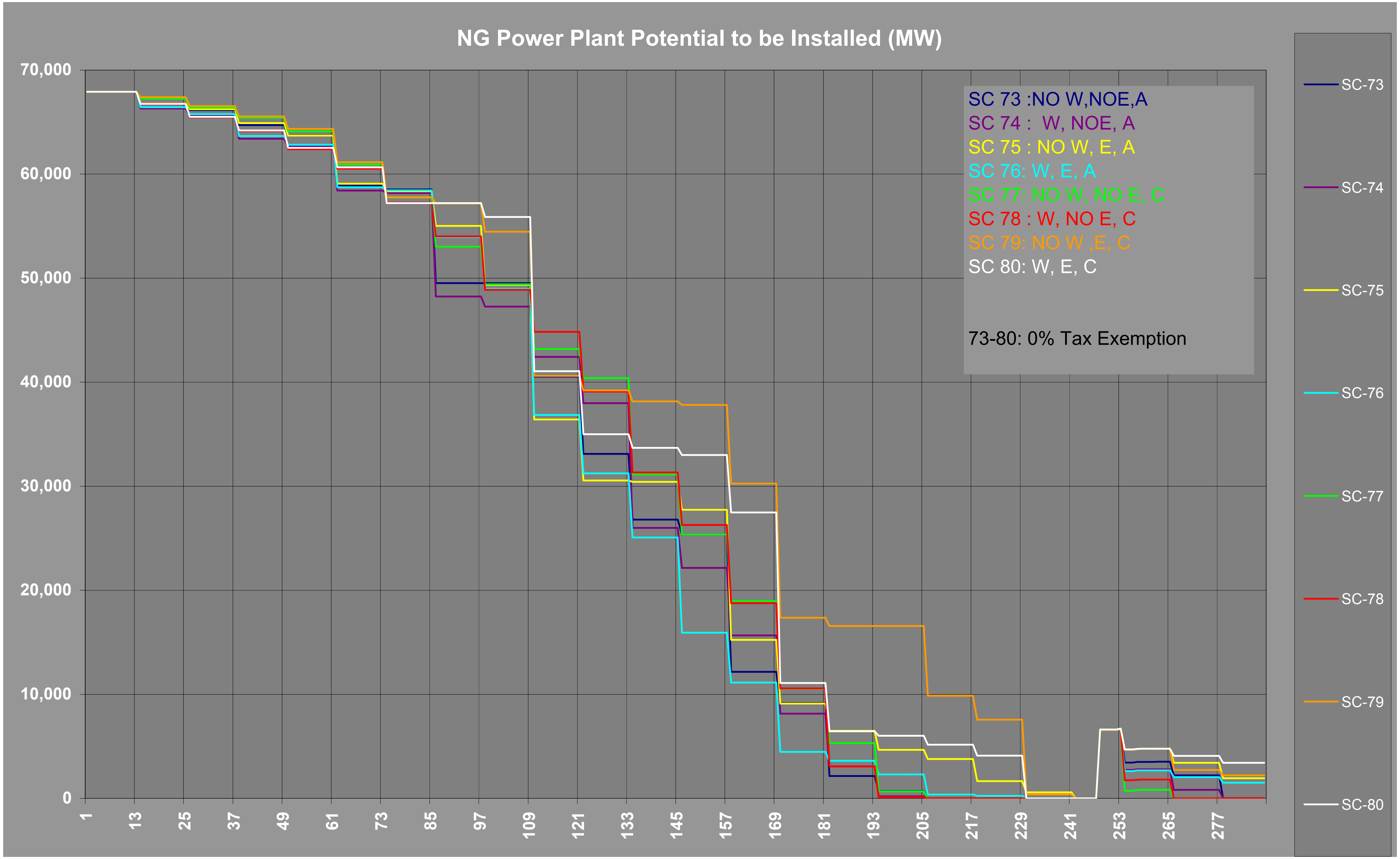
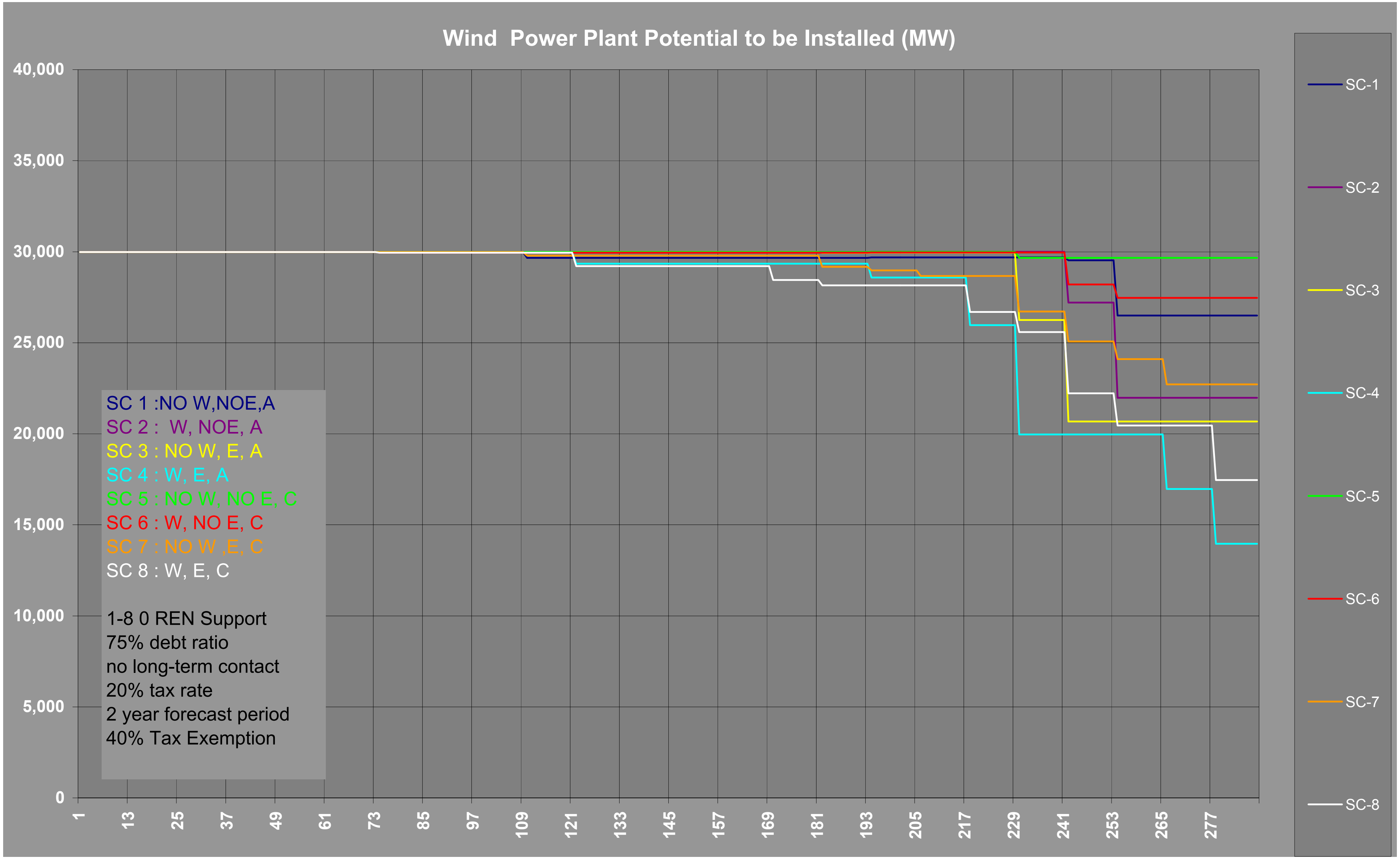
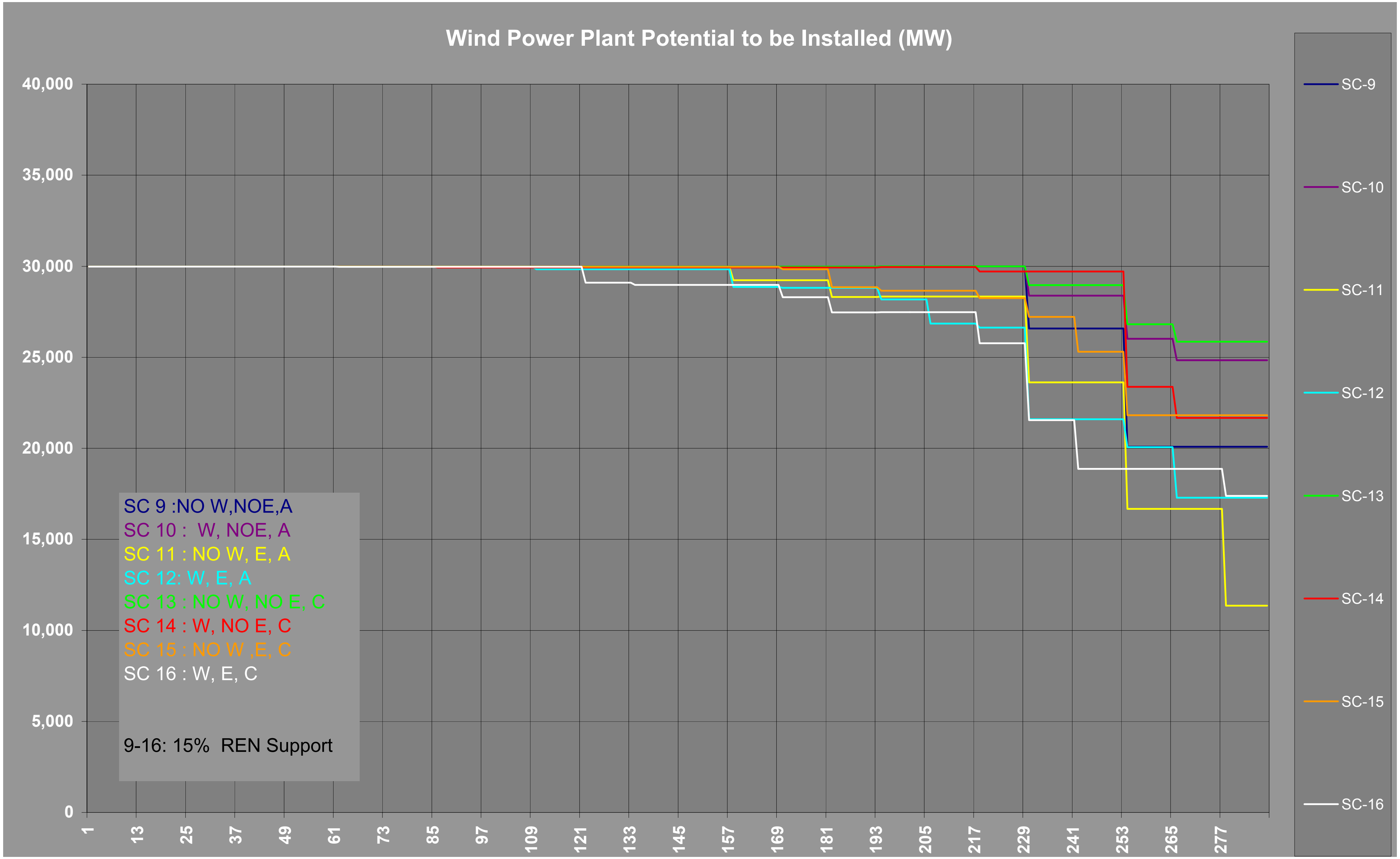
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



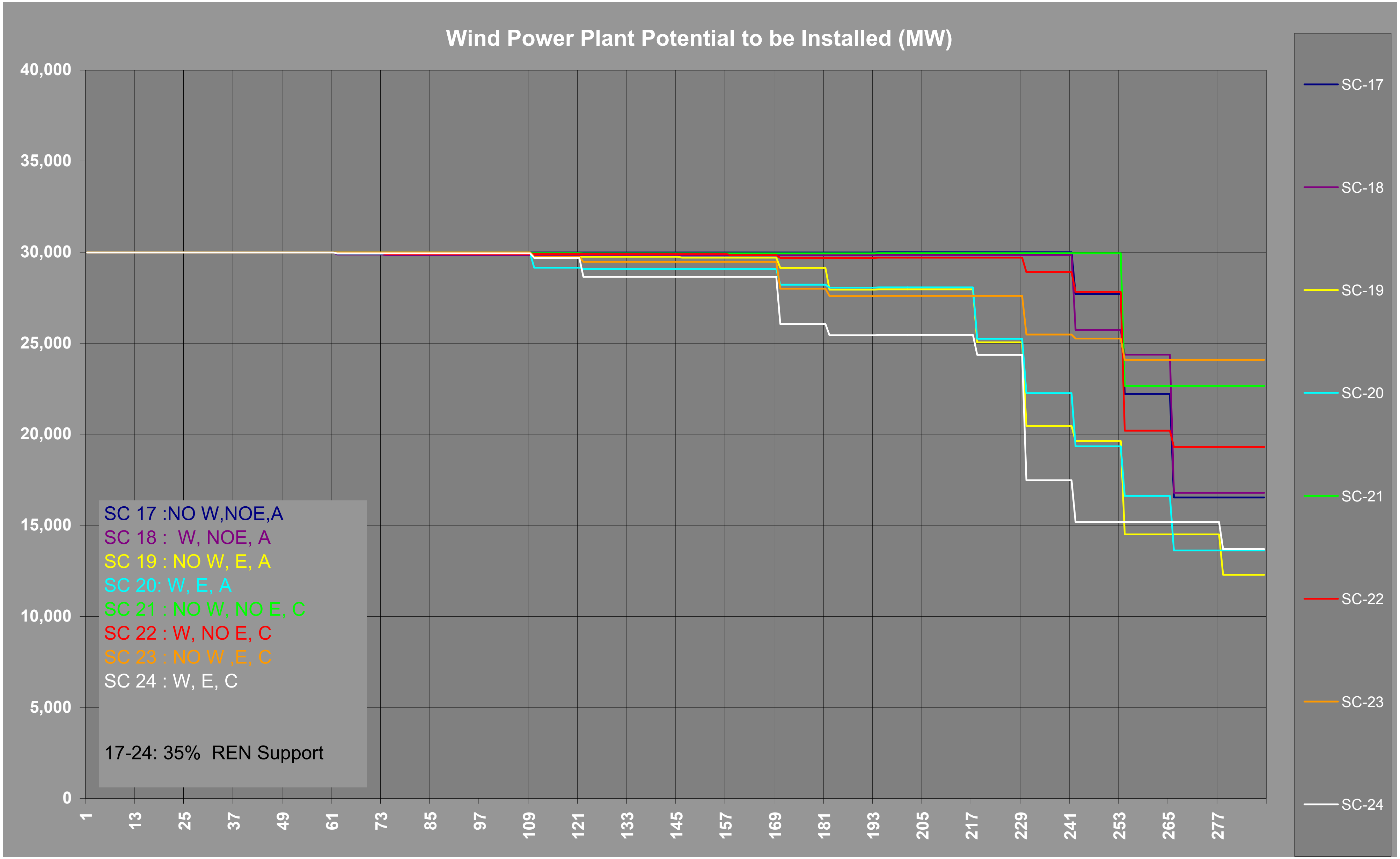
NG Power Plant Potential to be Installed (MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72


NG Power Plant Potential to be Installed (MW)
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80

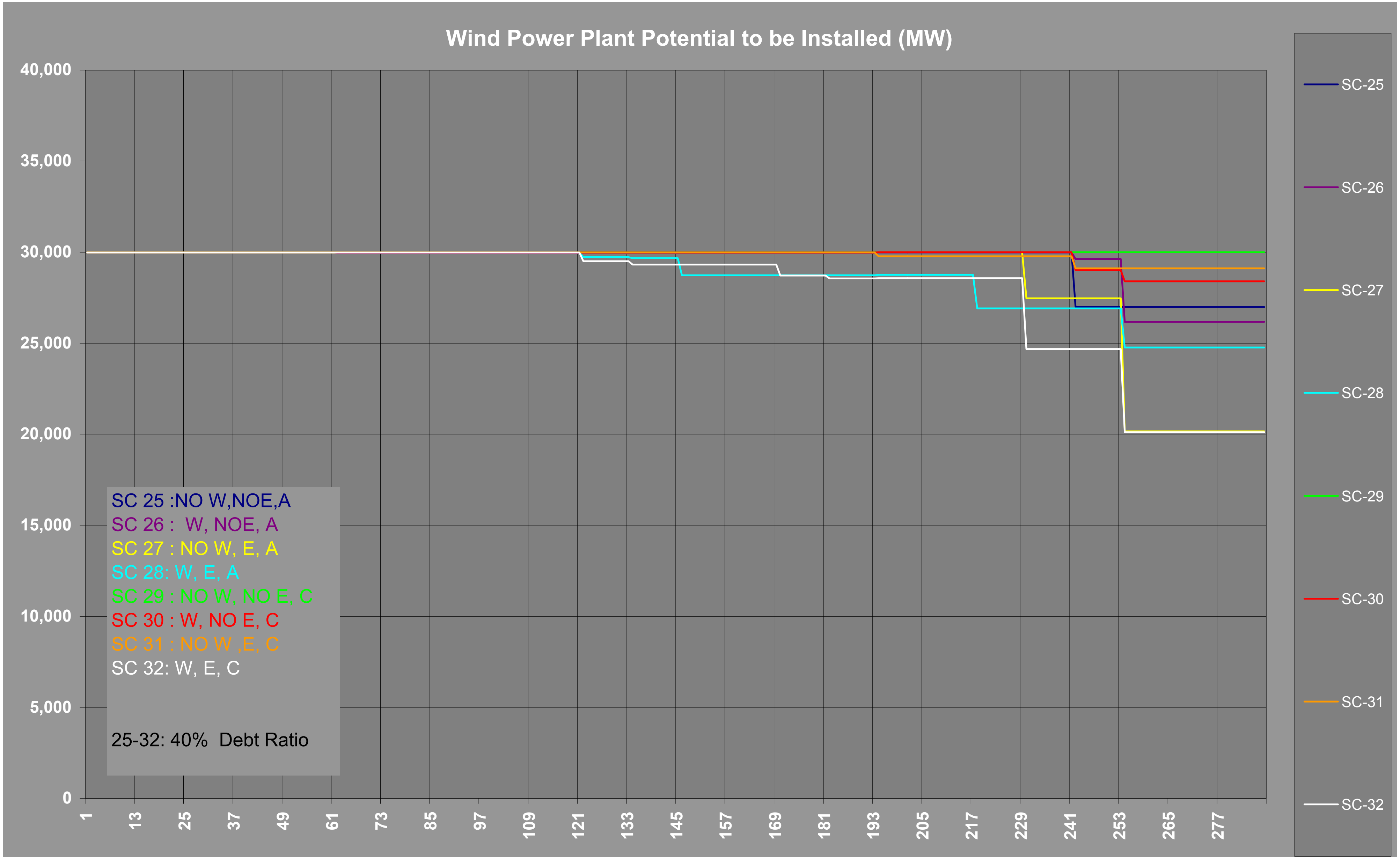

Wind Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8

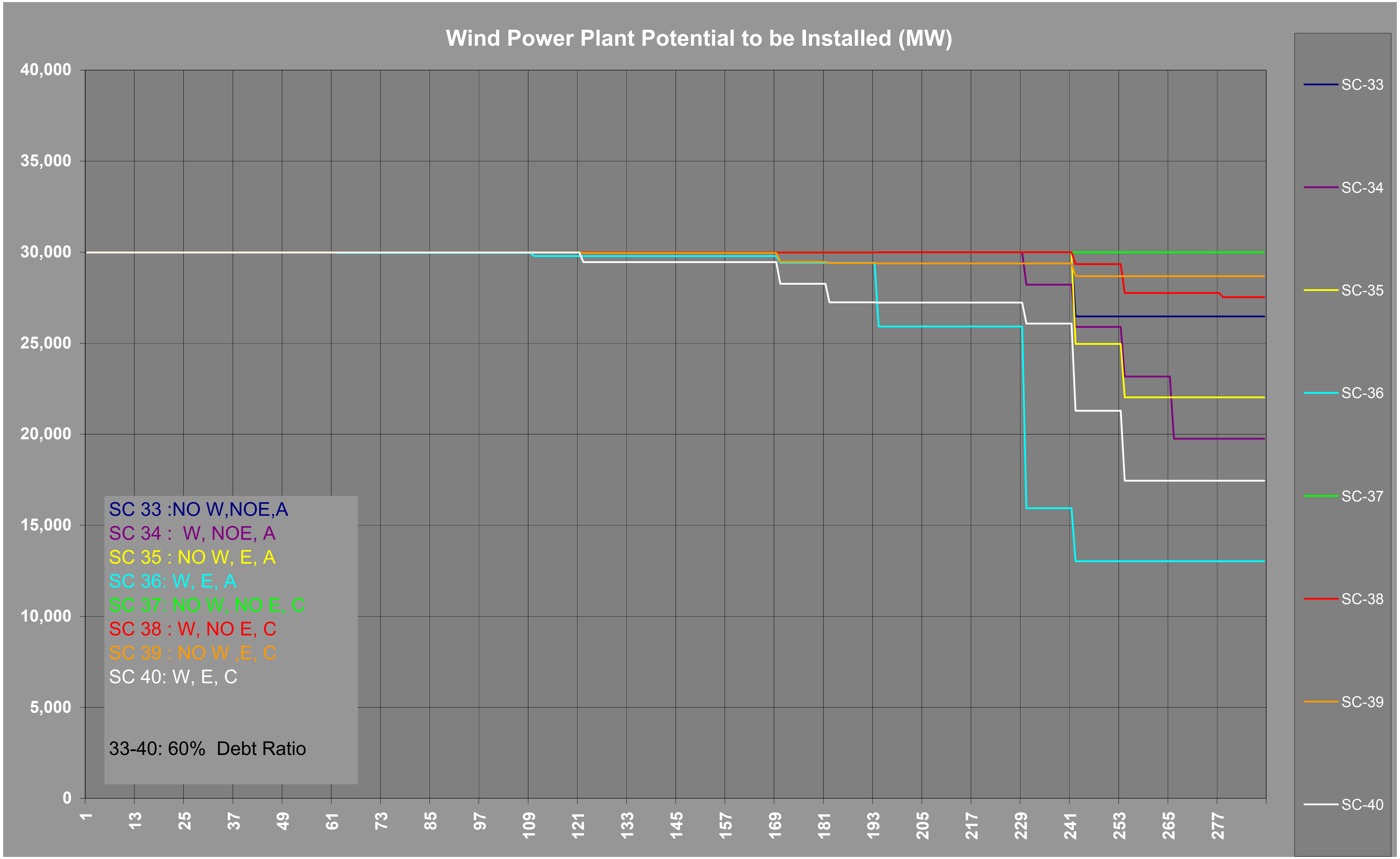


Wind Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16

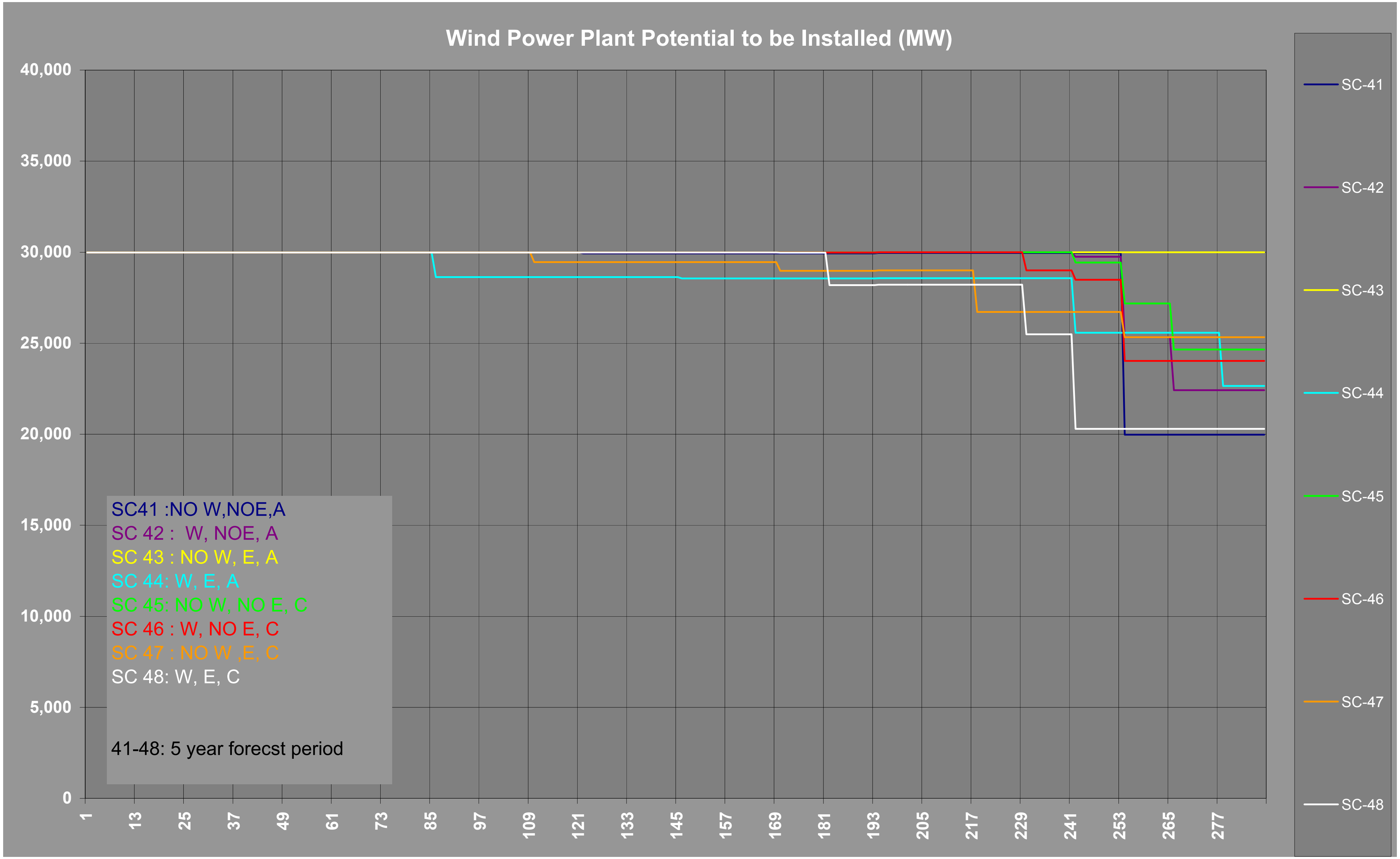


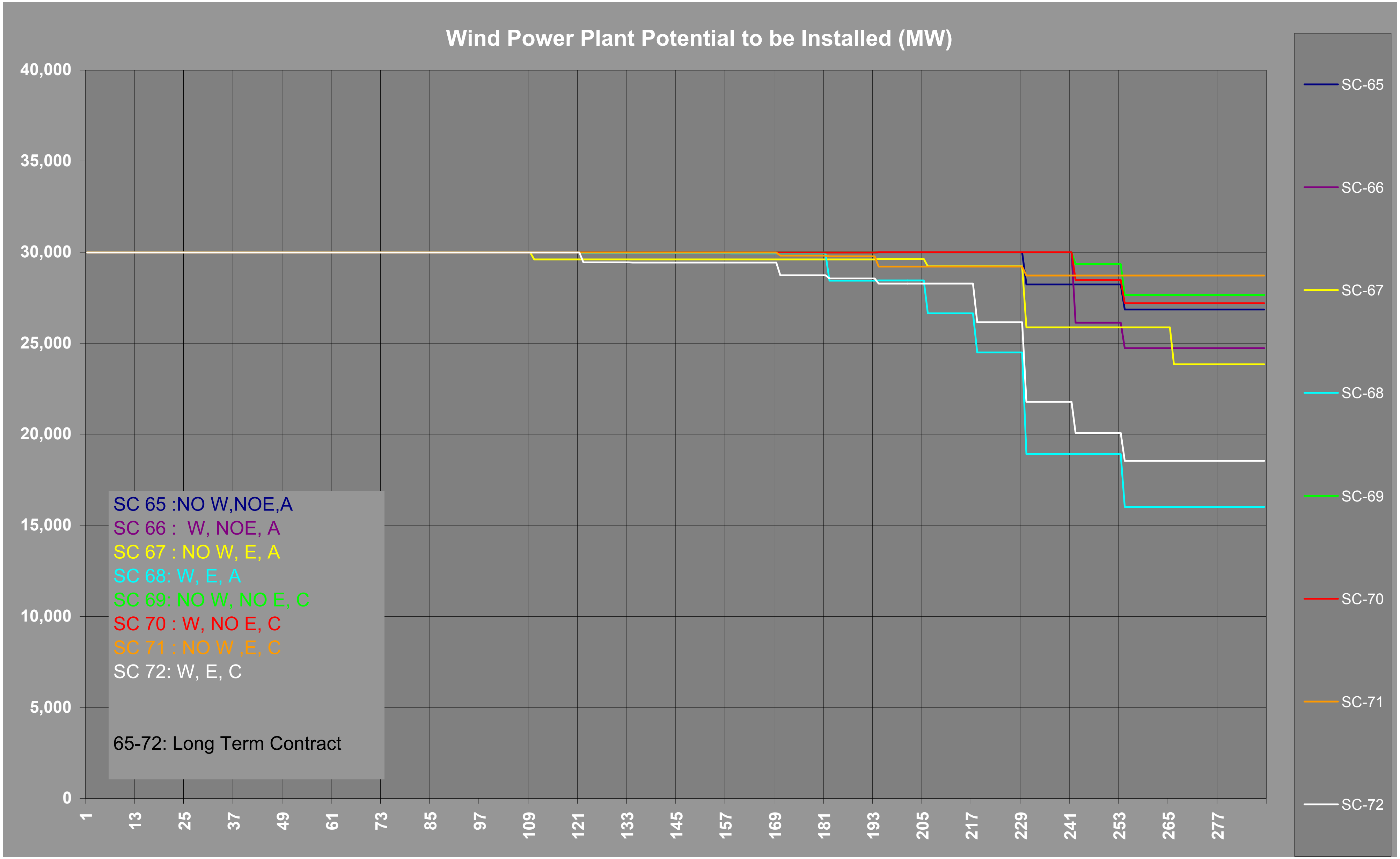
Wind Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24


Wind Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32

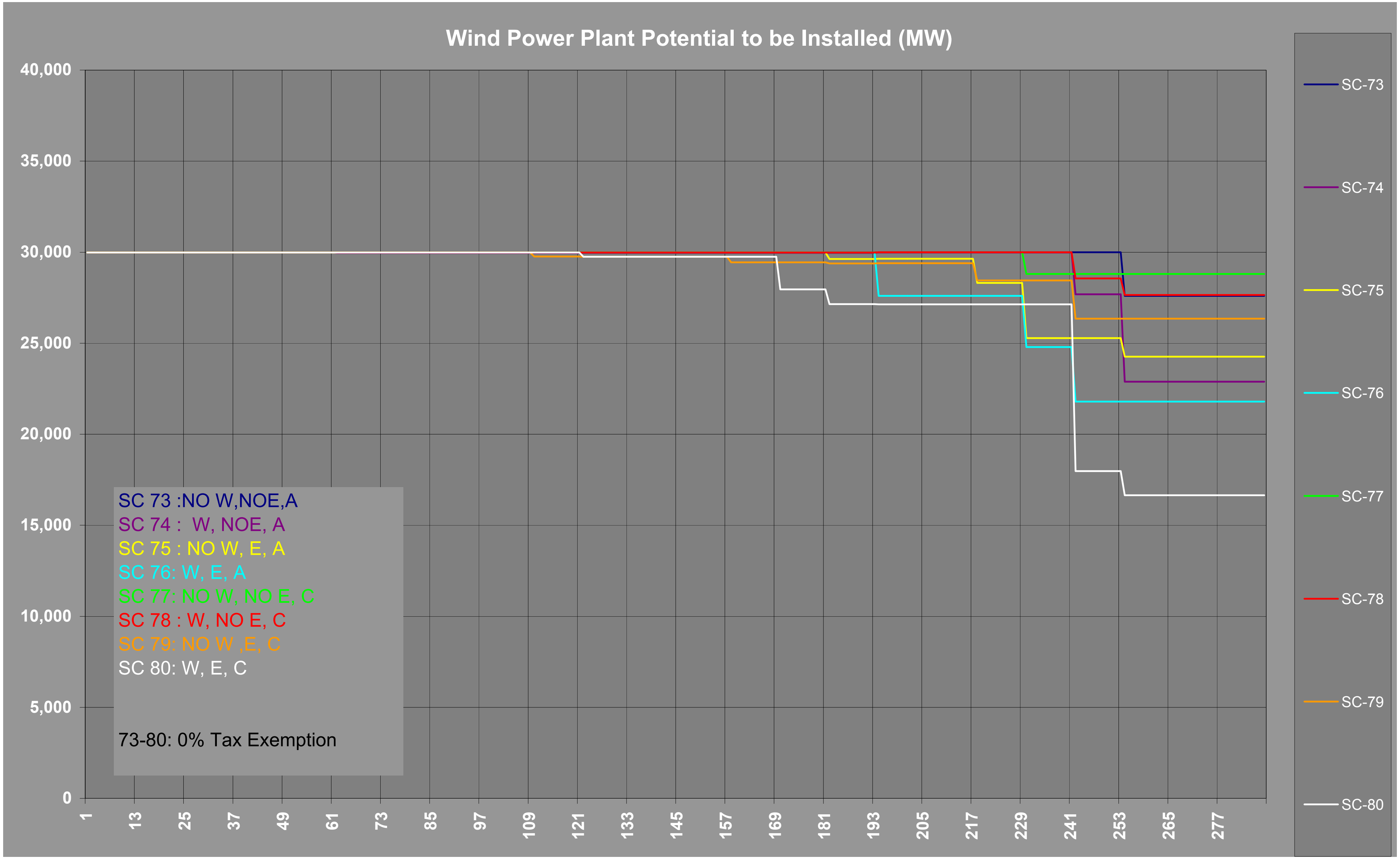


Wind Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40

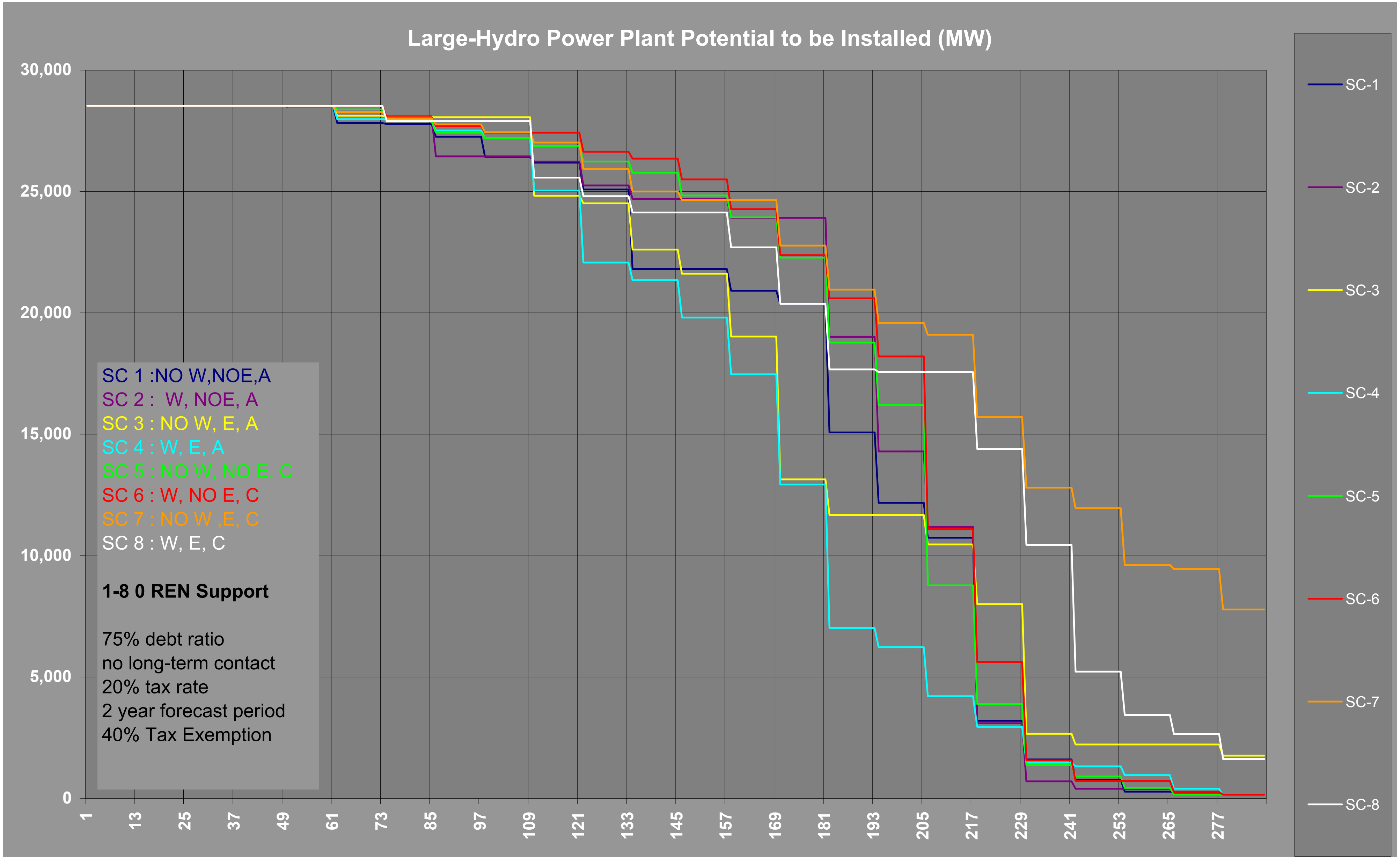

Wind Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period



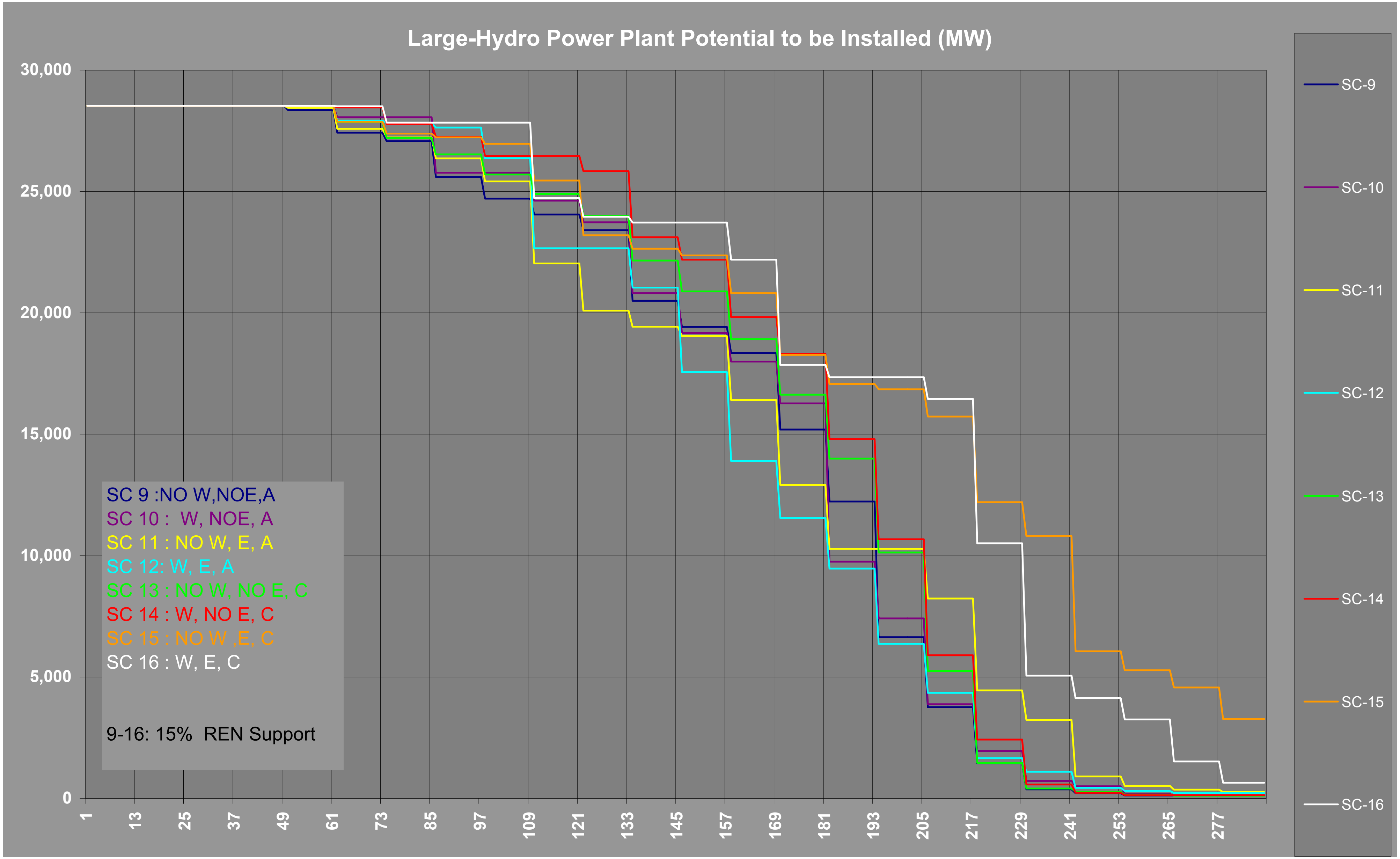
Wind Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract



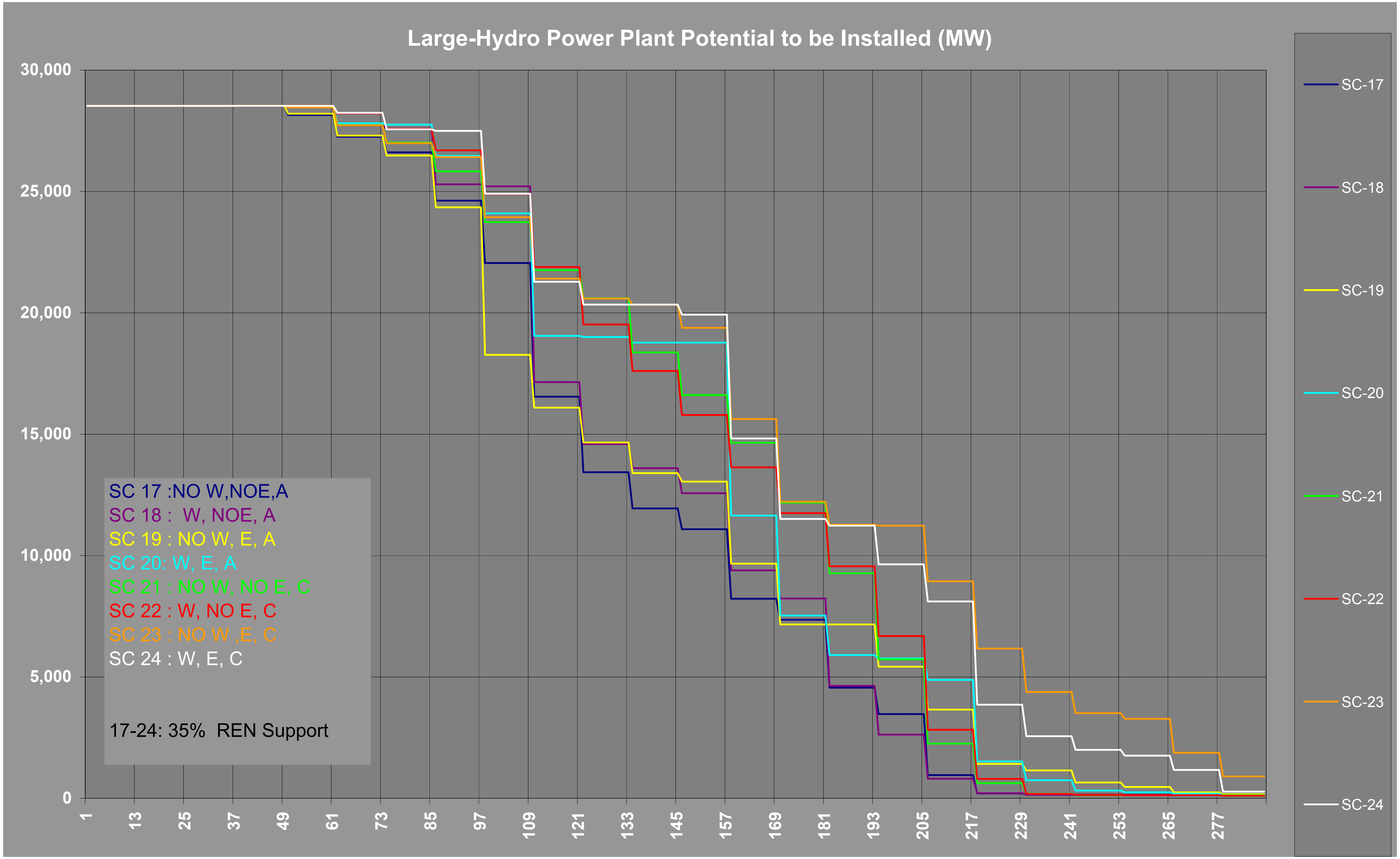
Wind Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



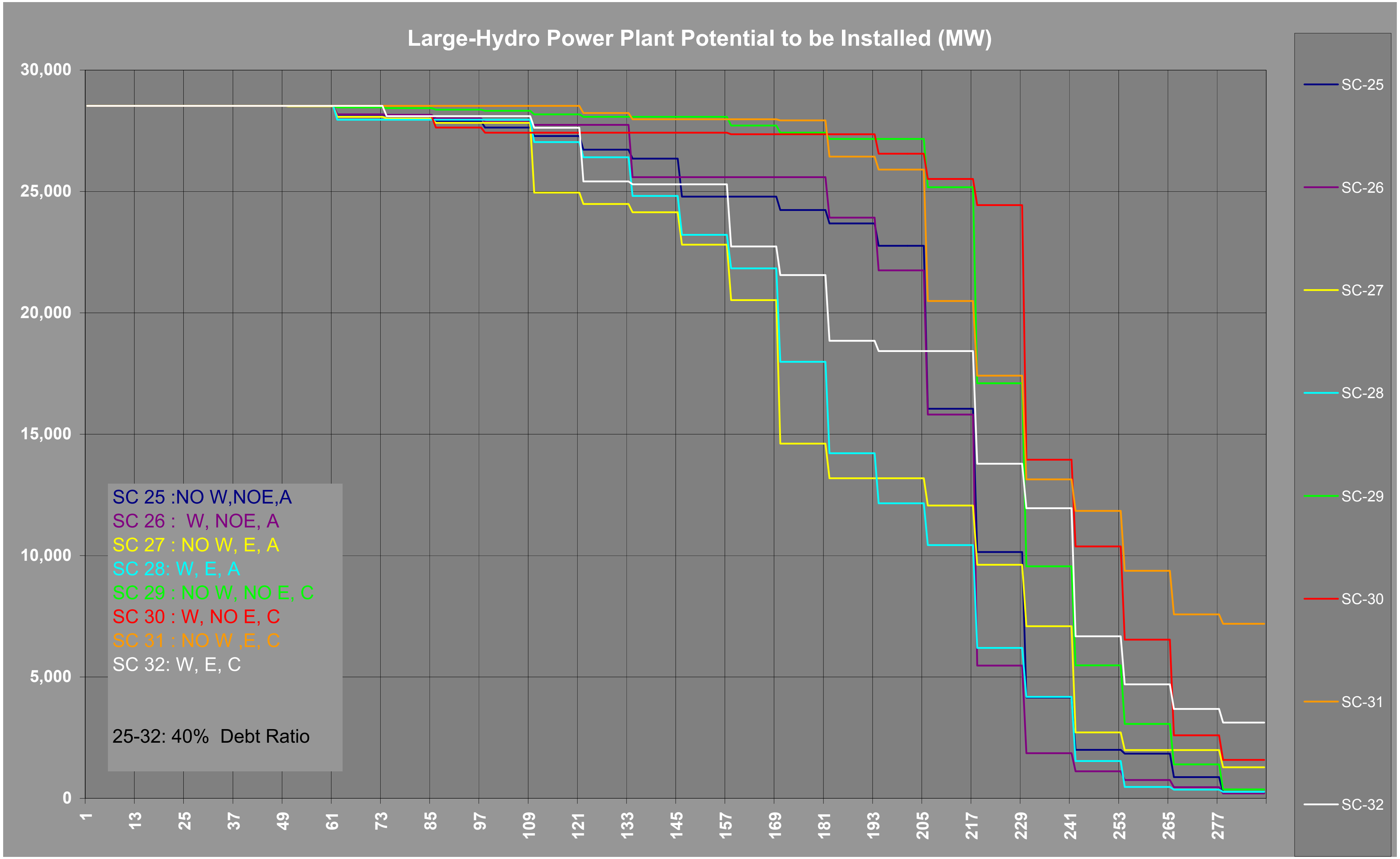
Large-Hydro Power Plant Potential to be Installed (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Large-Hydro Power Plant Potential to be Installed (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



Large-Hydro Power Plant Potential to be Installed (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24



Large-Hydro Power Plant Potential to be Installed (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
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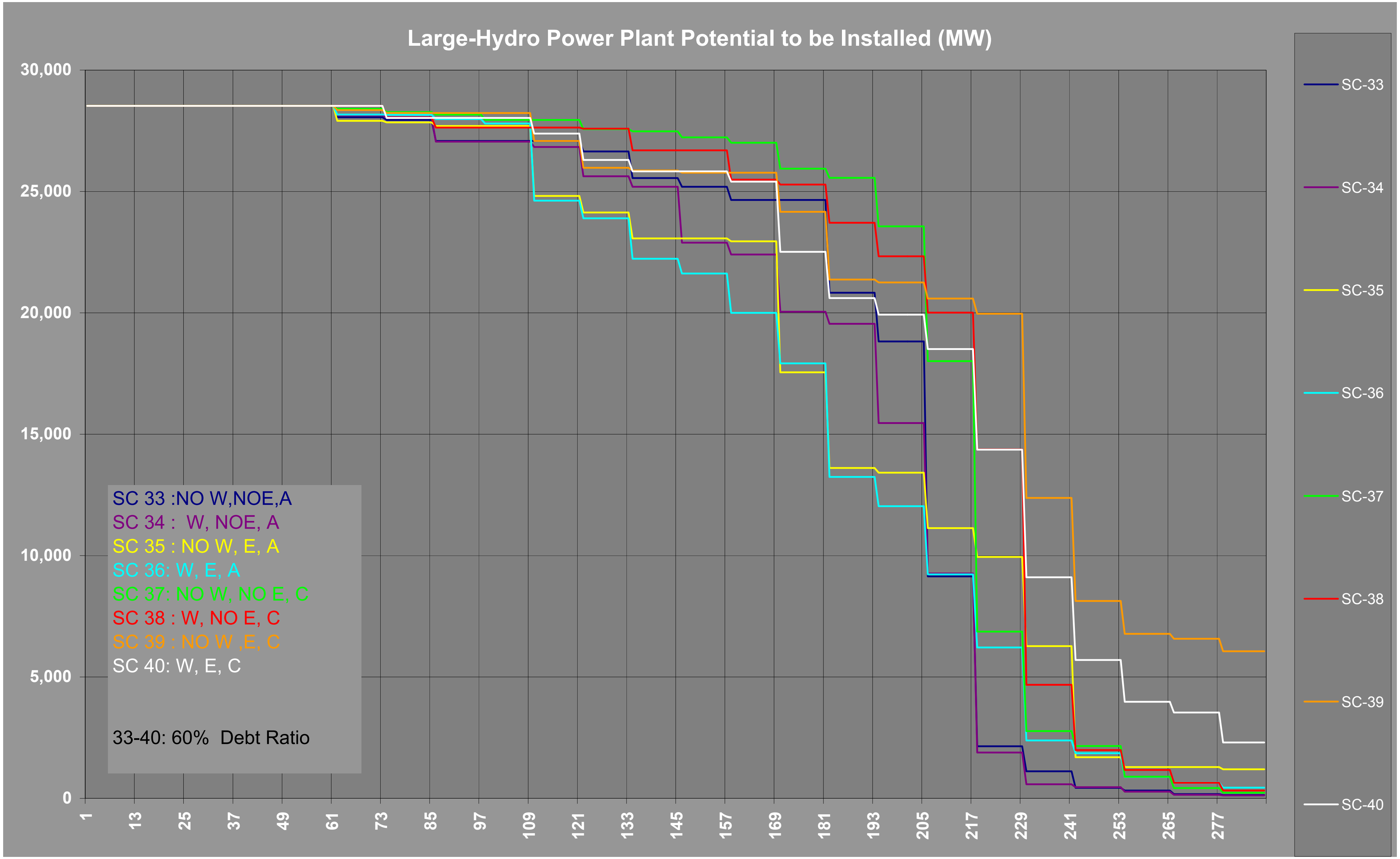
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio



Large-Hydro Power Plant Potential to be Installed (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
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37
49
61
73
85
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121
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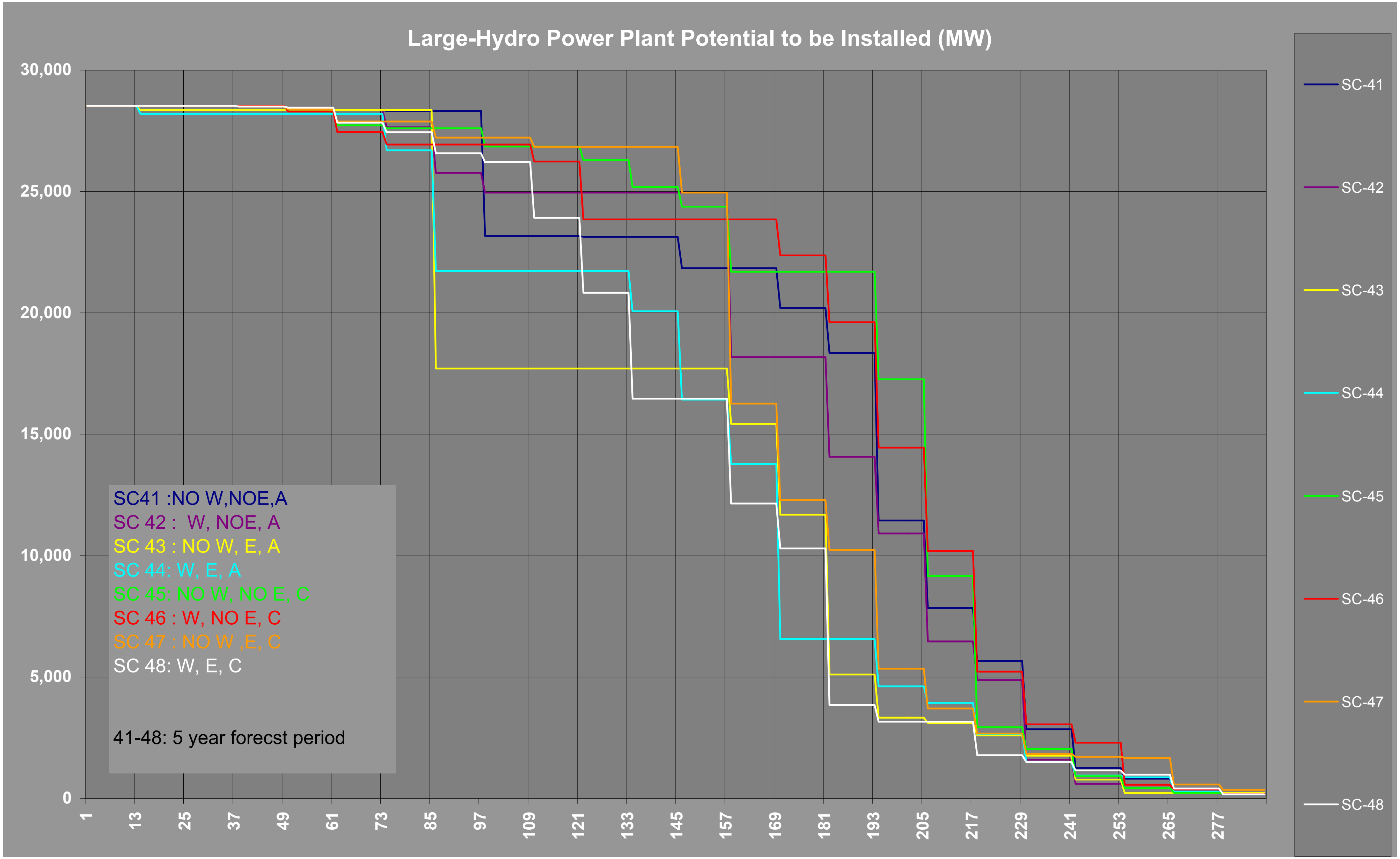
157
169
181
193
205
217
229
241
253
265
277
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40


Large-Hydro Power Plant Potential to be Installed (MW)
30,000
25,000
20,000
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145
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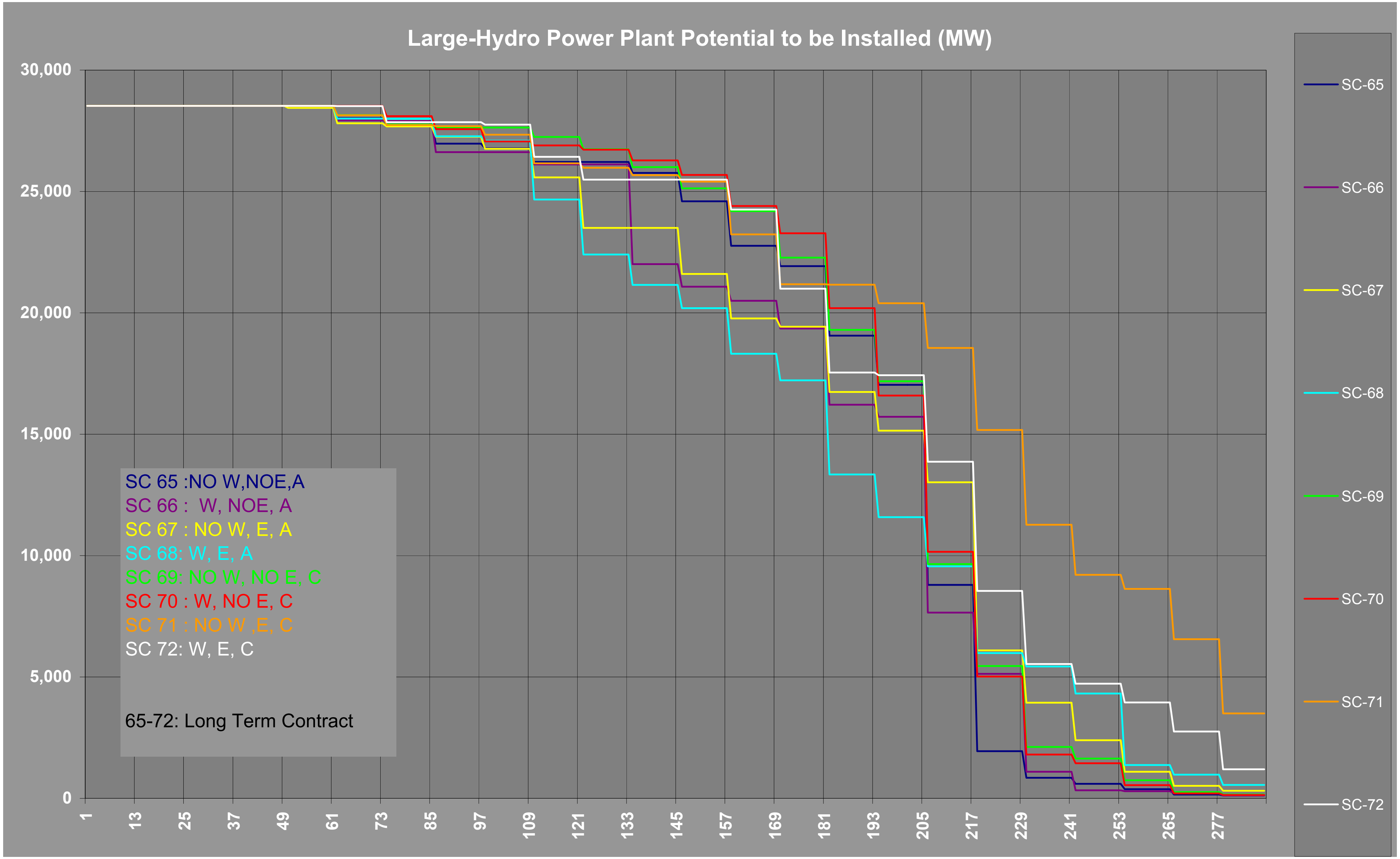
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period



Large-Hydro Power Plant Potential to be Installed (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
1
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25
37
49
61
73
85
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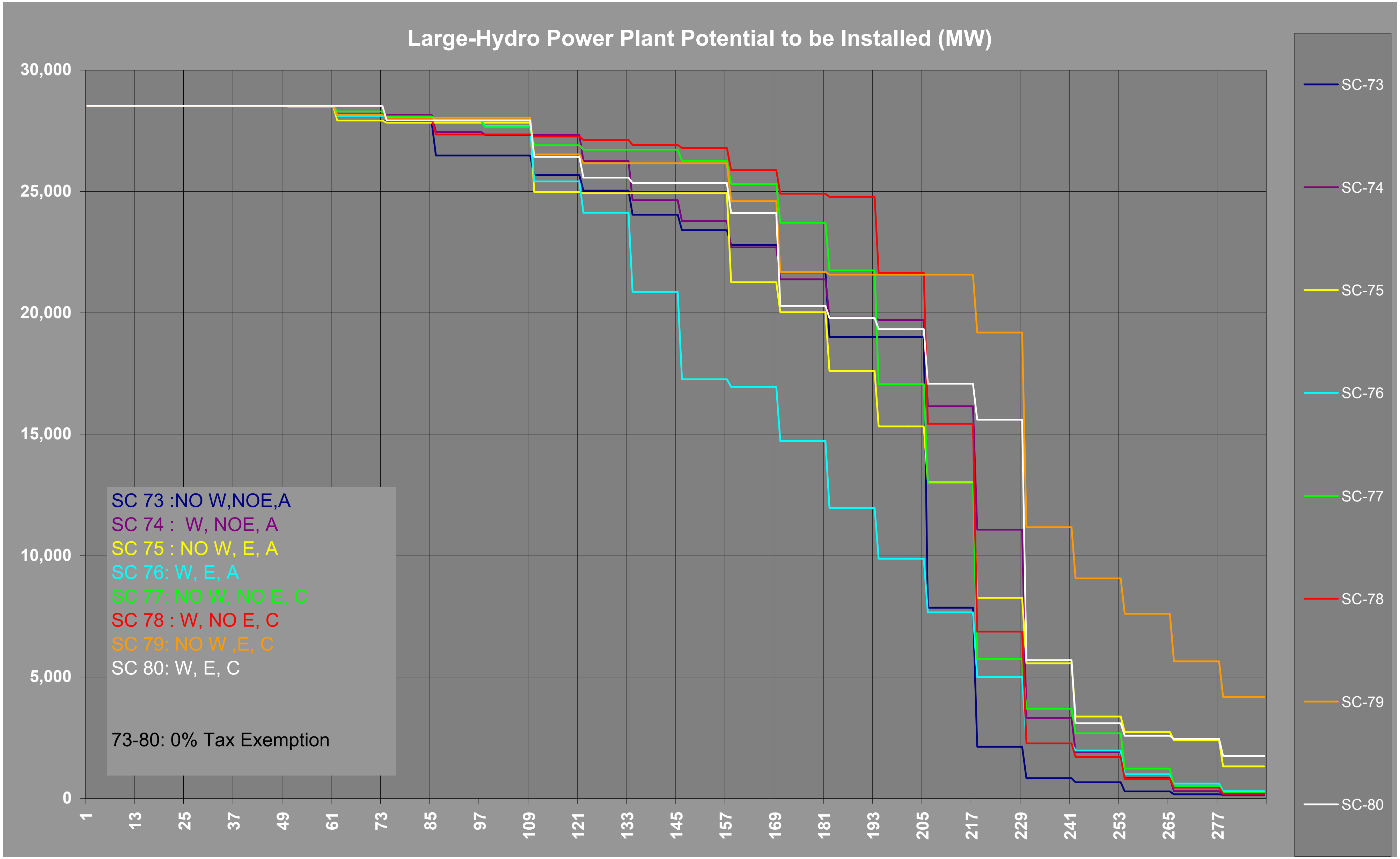
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



Large-Hydro Power Plant Potential to be Installed (MW)
30,000
25,000
20,000
15,000
10,000
5,000
0
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133
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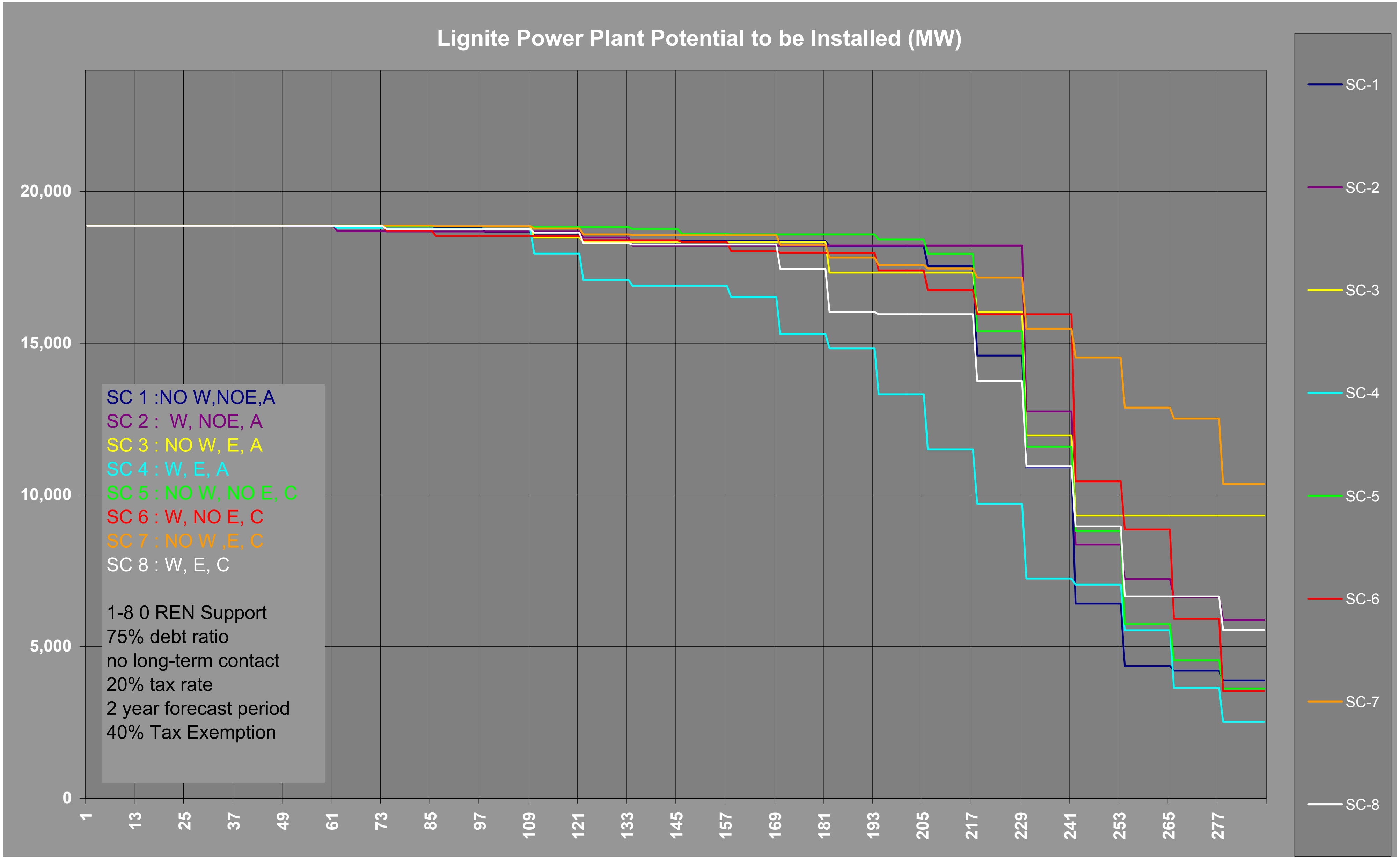
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



Lignite Power Plant Potential to be Installed (MW)
20,000
15,000
10,000
5,000
0
1
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25
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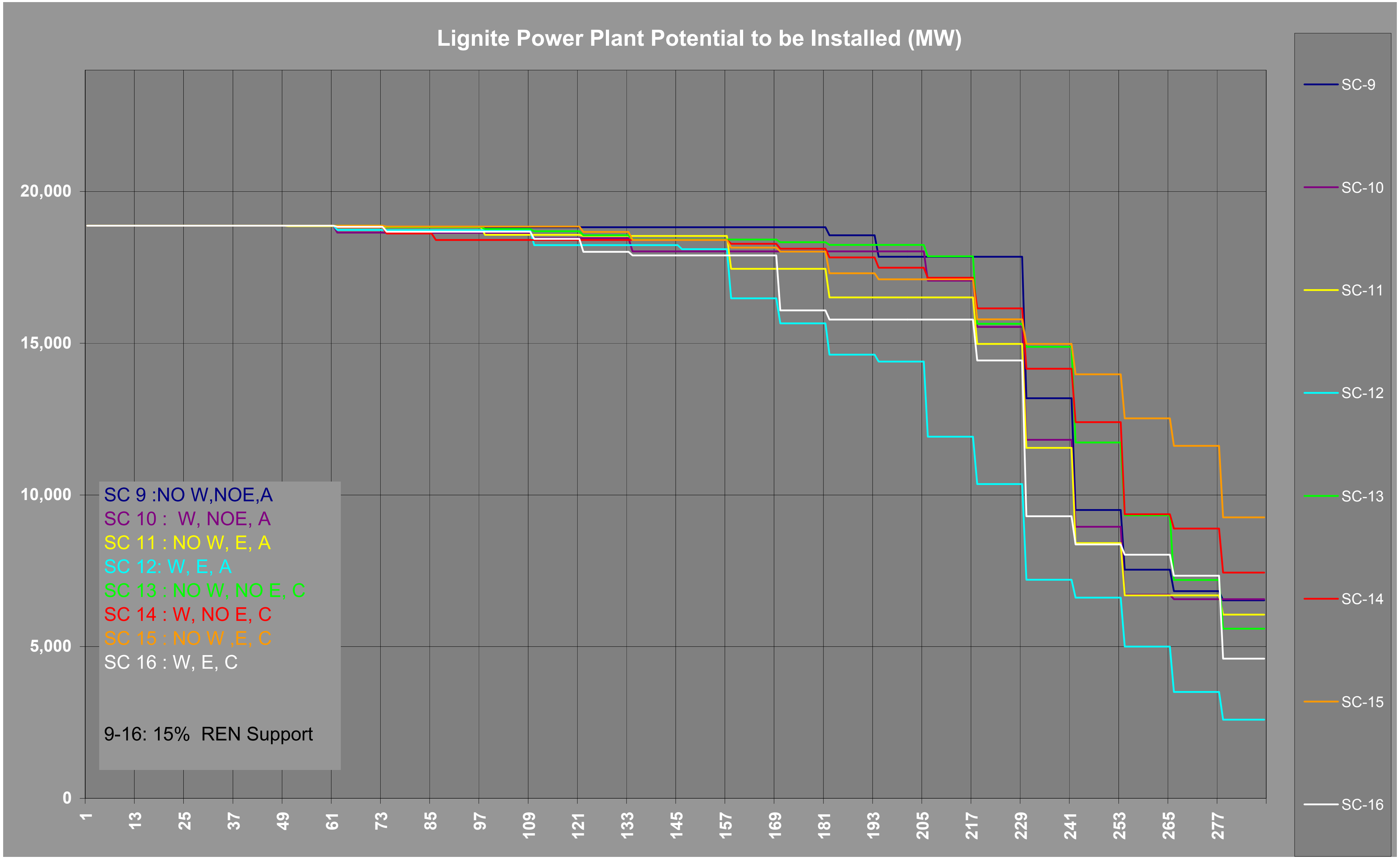
181
193
205
217
229
241
253
265
277
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Lignite Power Plant Potential to be Installed (MW)
20,000
15,000
10,000
5,000
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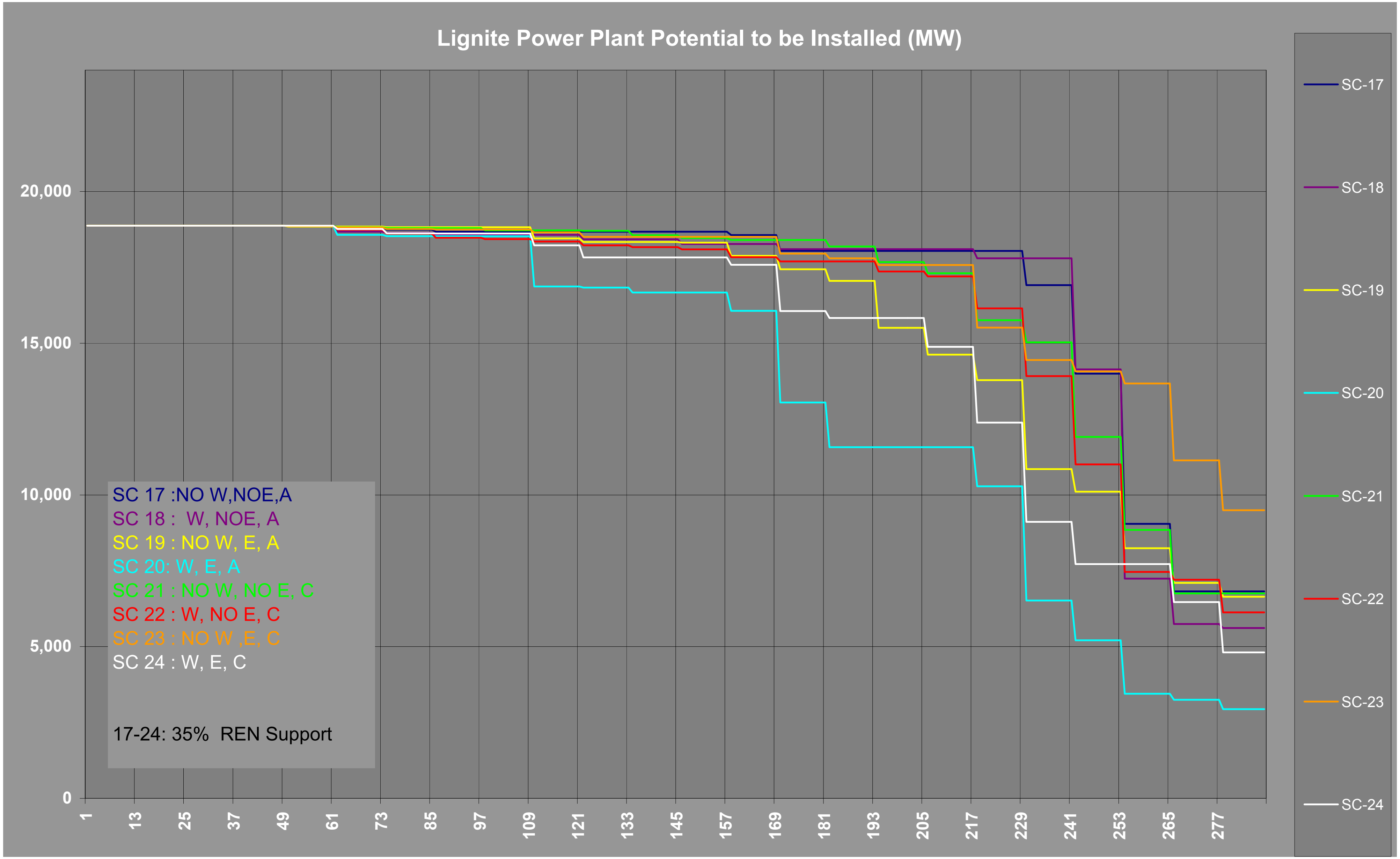
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support


Lignite Power Plant Potential to be Installed (MW)
20,000
15,000
10,000
5,000
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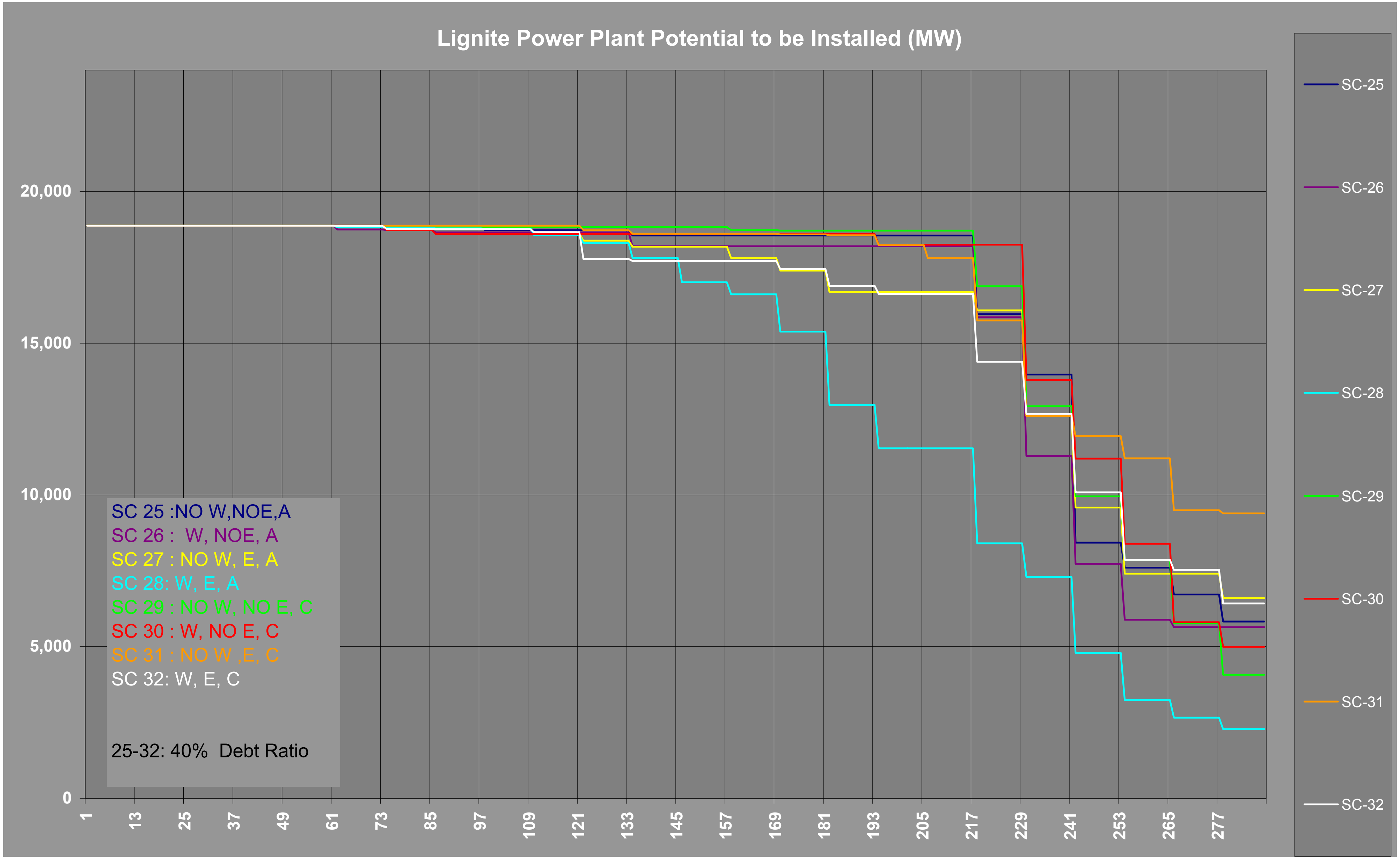
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support


Lignite Power Plant Potential to be Installed (MW)
20,000
15,000
10,000
5,000
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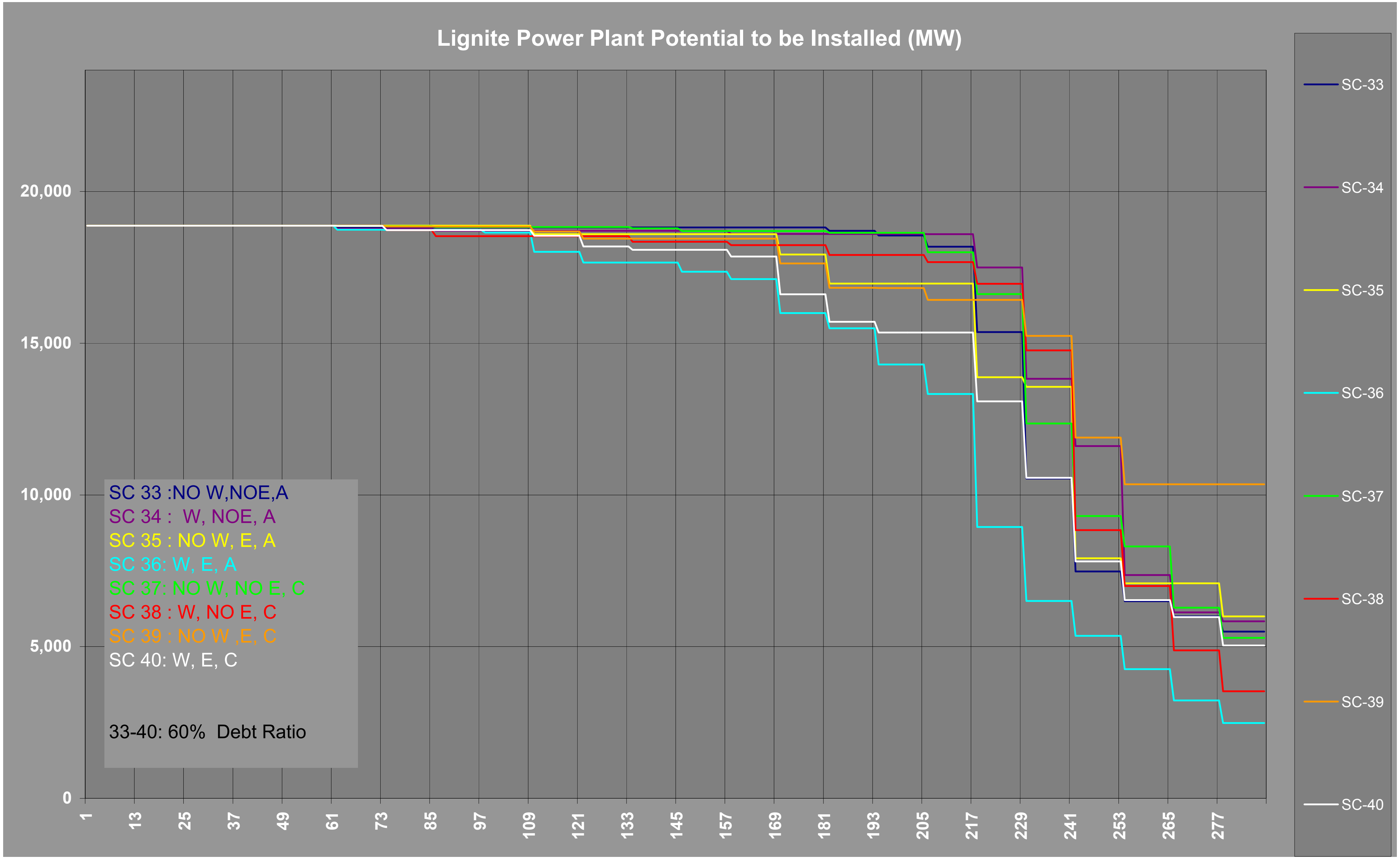
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



Lignite Power Plant Potential to be Installed (MW)
20,000
15,000
10,000
5,000
0
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25
37
49
61
73
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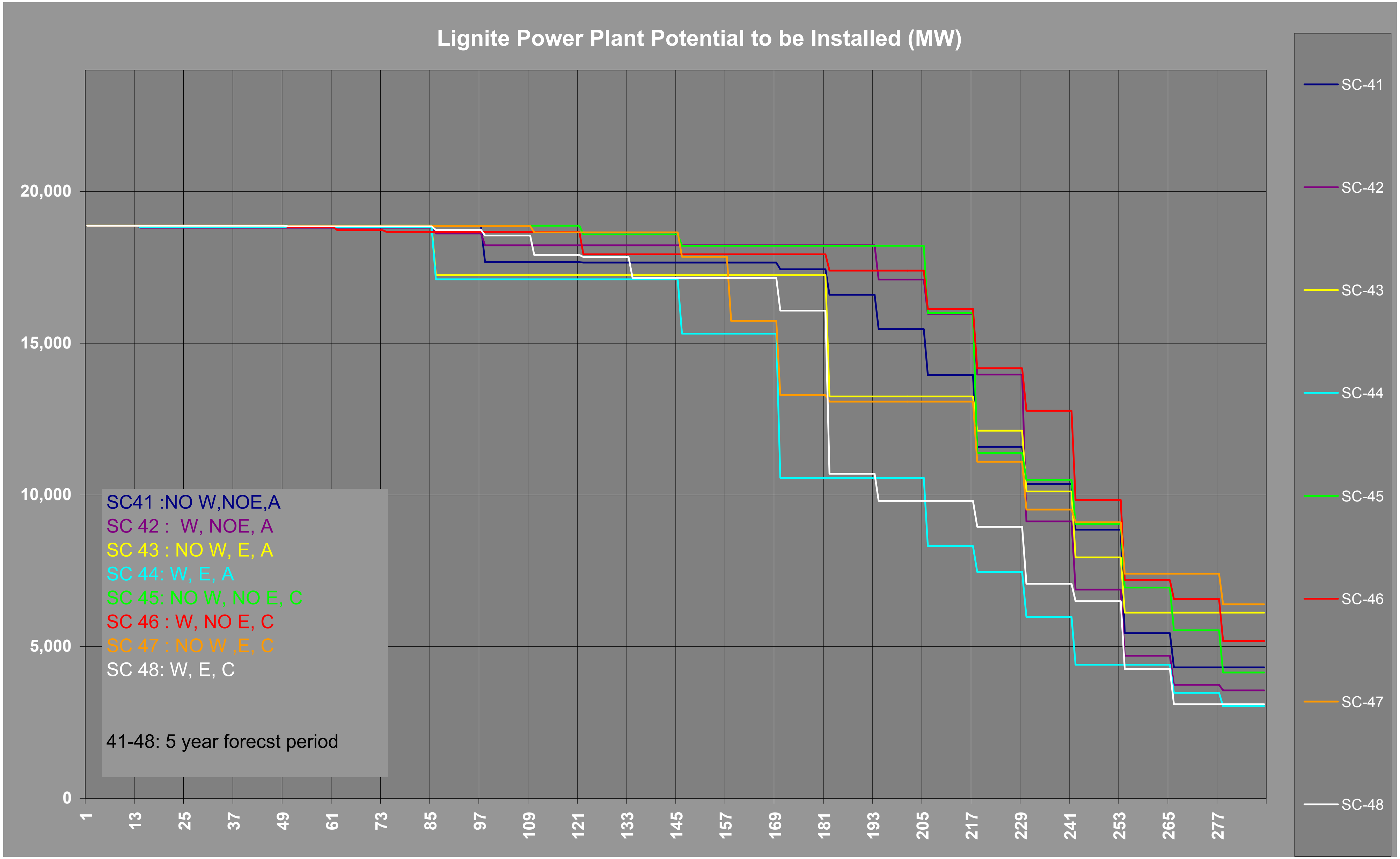
145
157
169
181
193
205
217
229
241
253
265
277
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40


Lignite Power Plant Potential to be Installed (MW)
20,000
15,000
10,000
5,000
0
1
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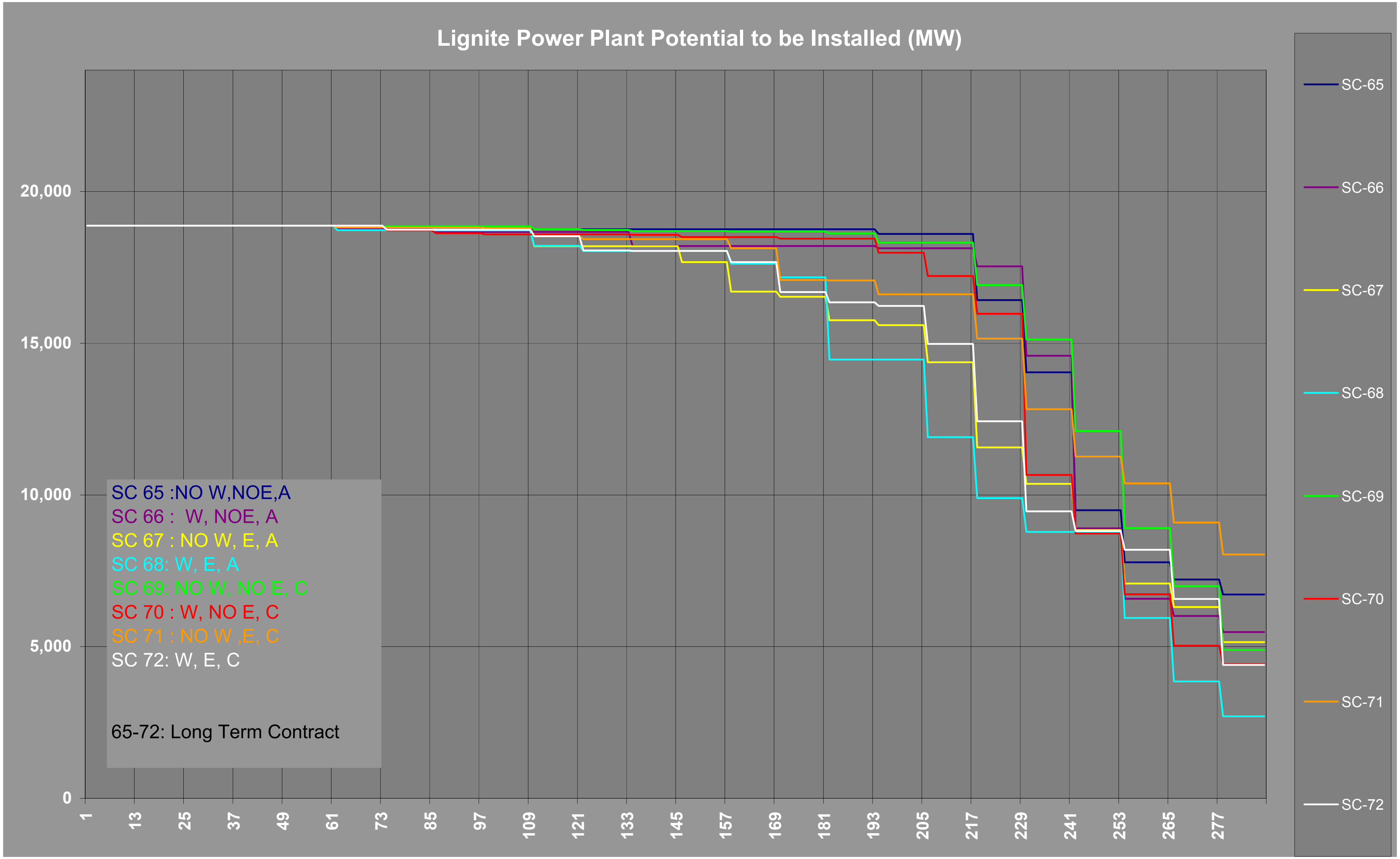
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



Lignite Power Plant Potential to be Installed (MW)
20,000
15,000
10,000
5,000
0
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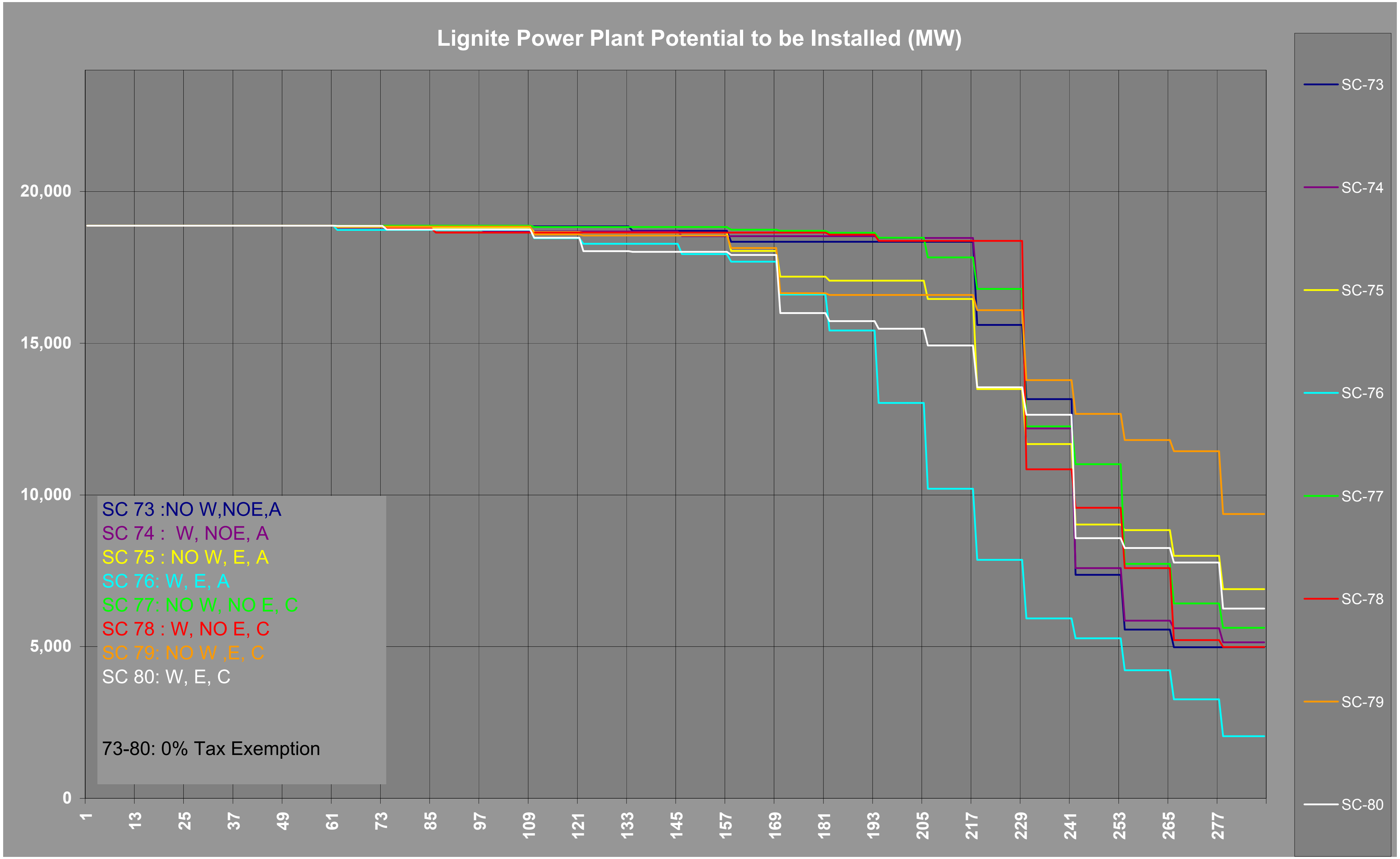
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



Lignite Power Plant Potential to be Installed (MW)
20,000
15,000
10,000
5,000
0
1
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25
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49
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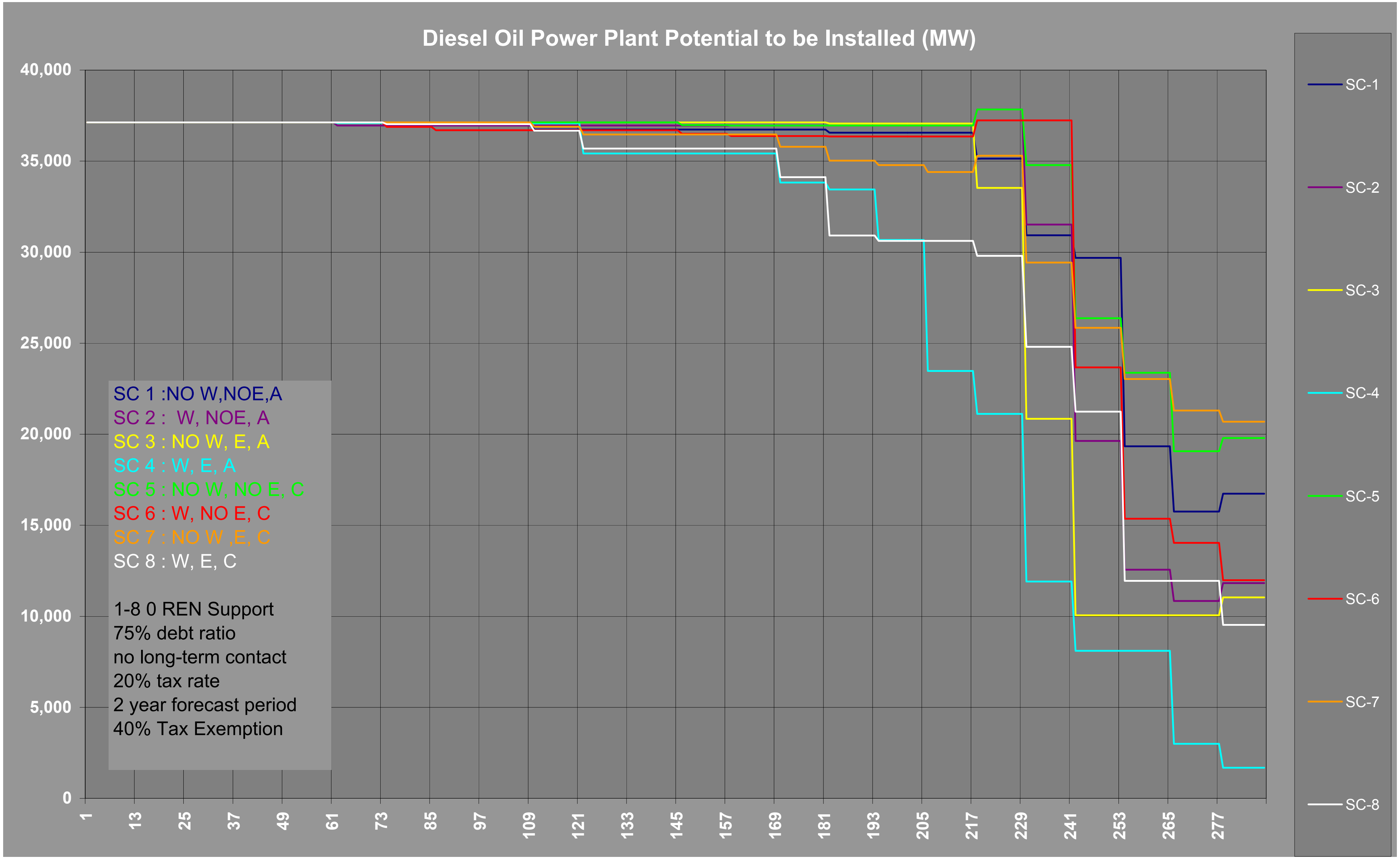
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption



Diesel Oil Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
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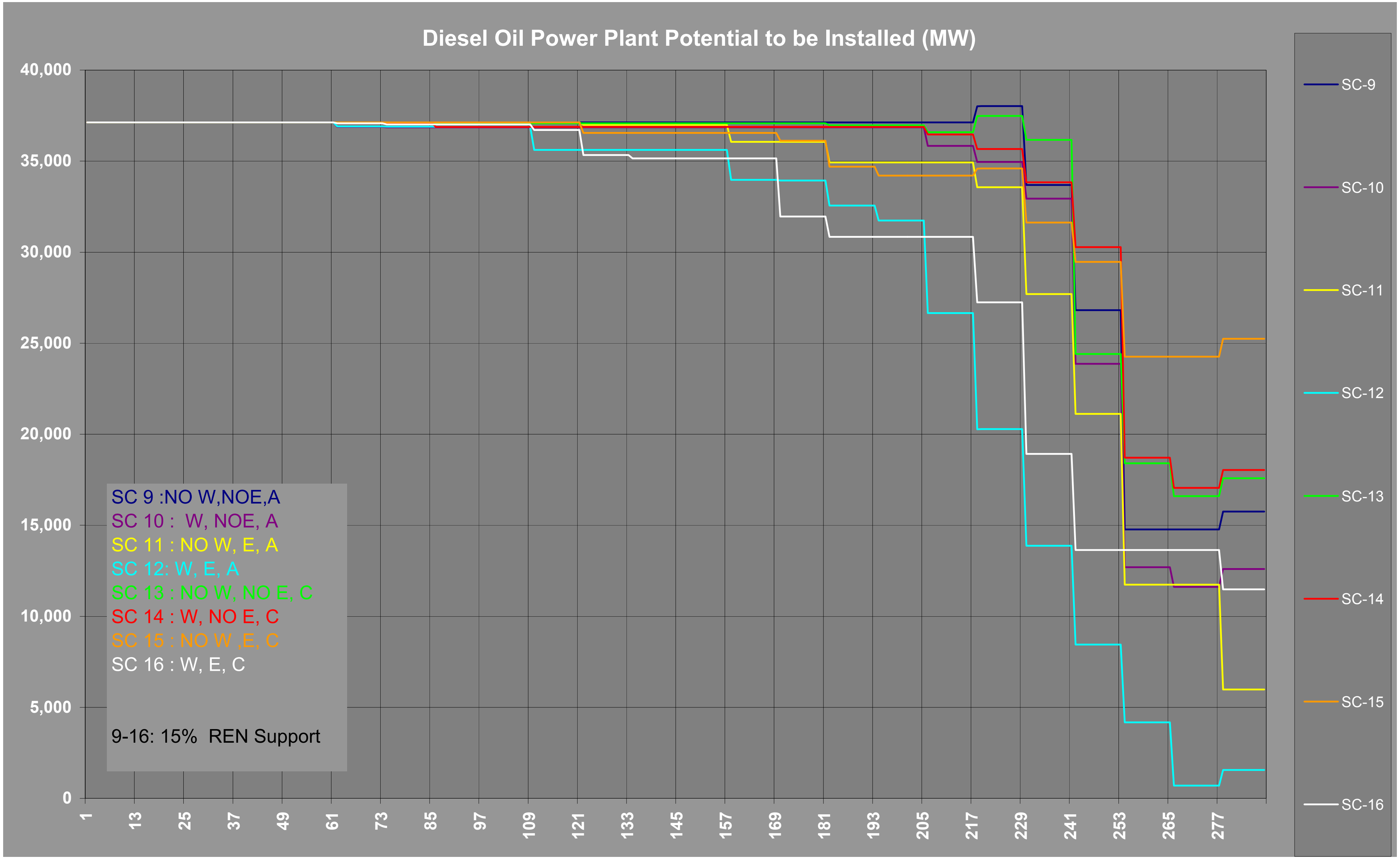
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption



Diesel Oil Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
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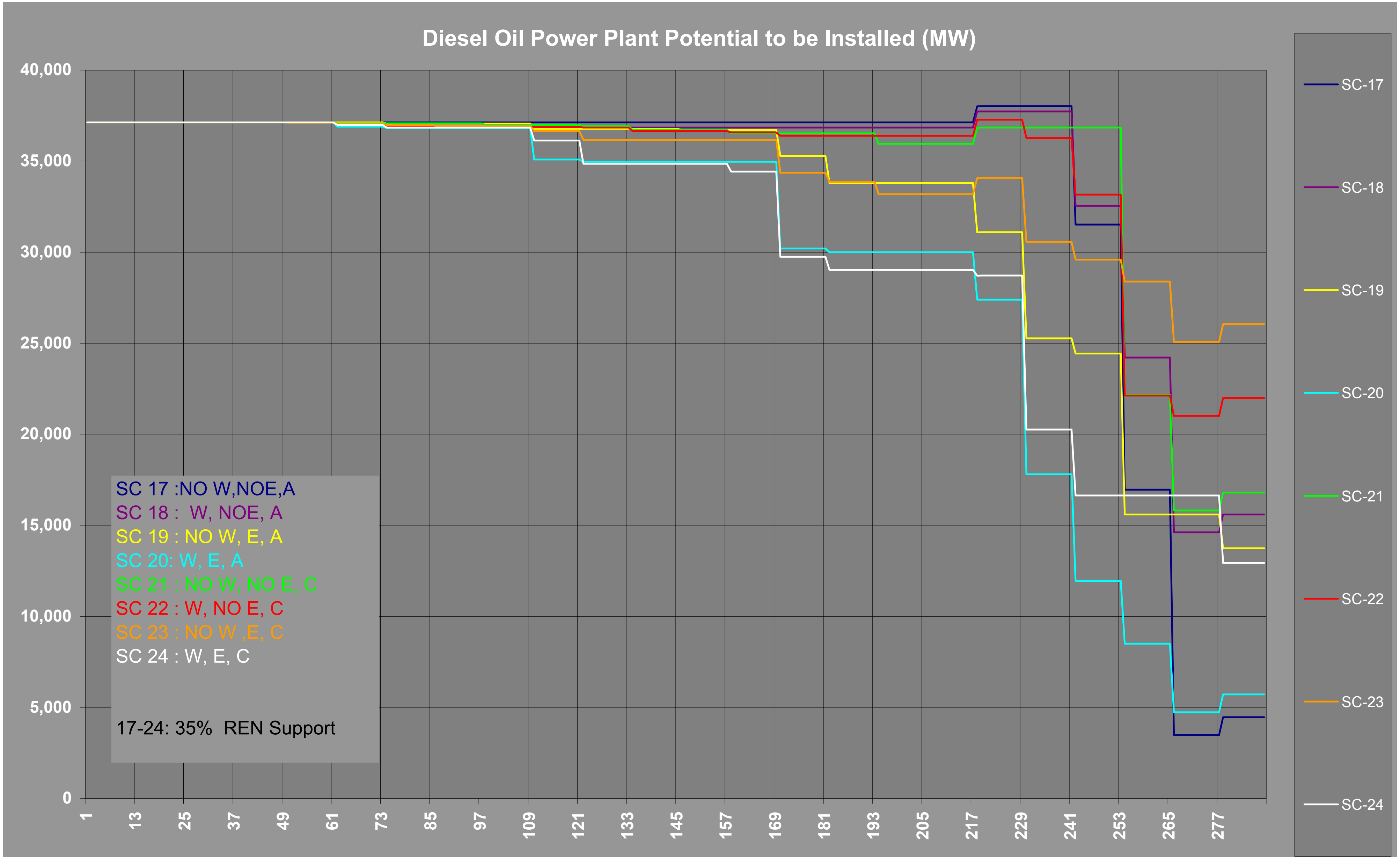
253
265
277
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16



Diesel Oil Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
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145
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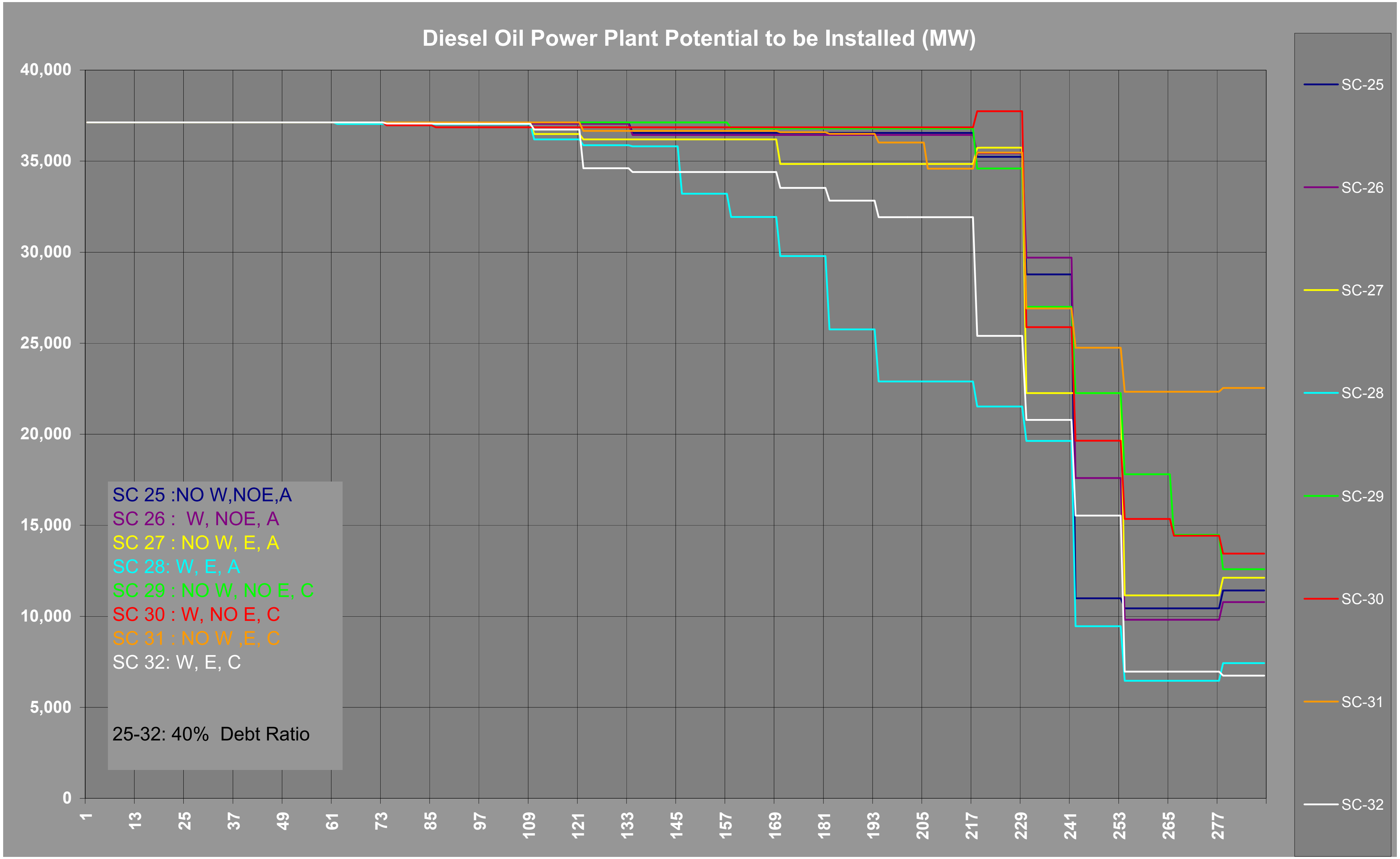
181
193
205
217
229
241
253
265
277
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24



Diesel Oil Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
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10,000
5,000
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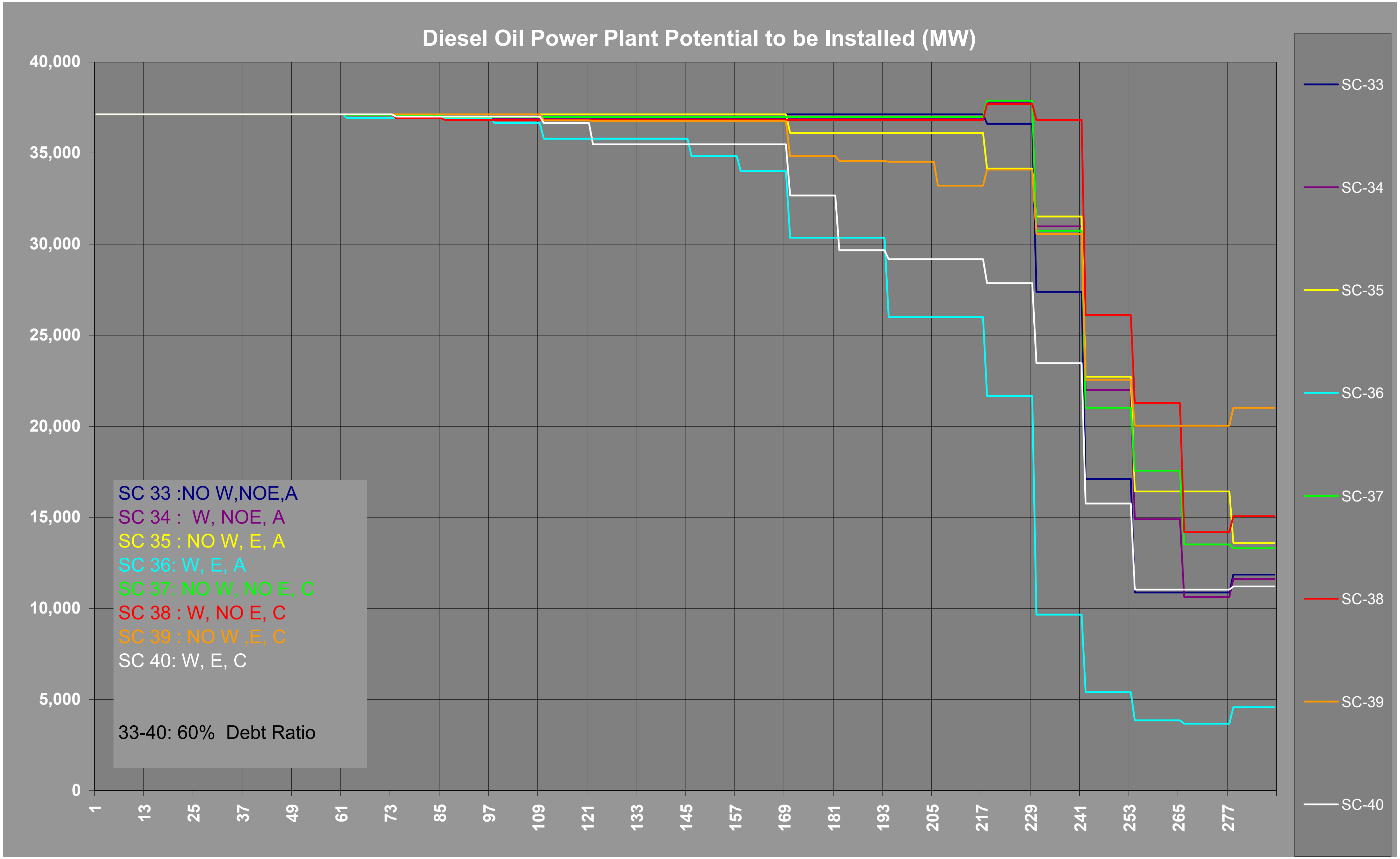
181
193
205
217
229
241
253
265
277
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio


Diesel Oil Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
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37
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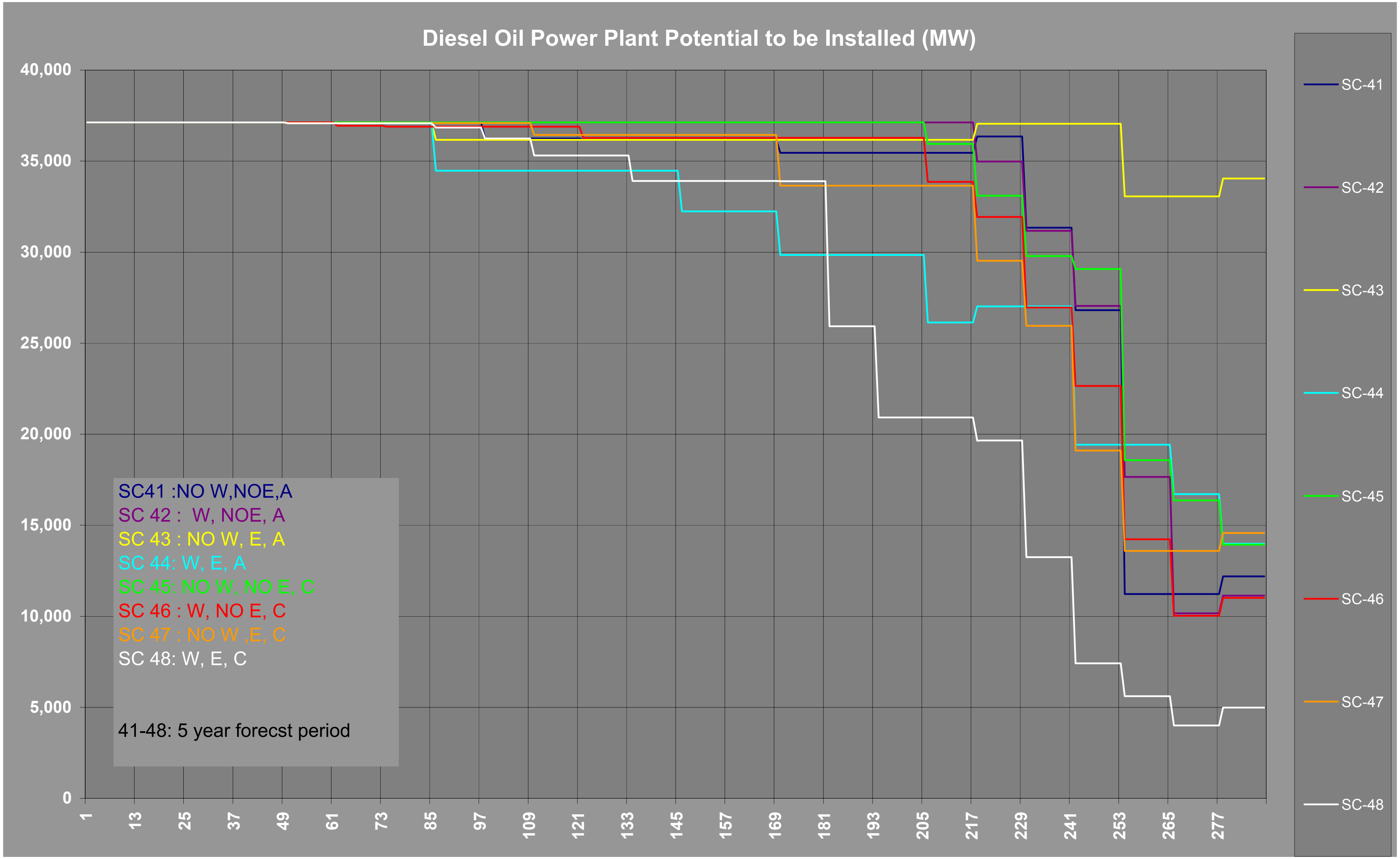
241
253
265
277
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40



Diesel Oil Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
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37
49
61
73
85
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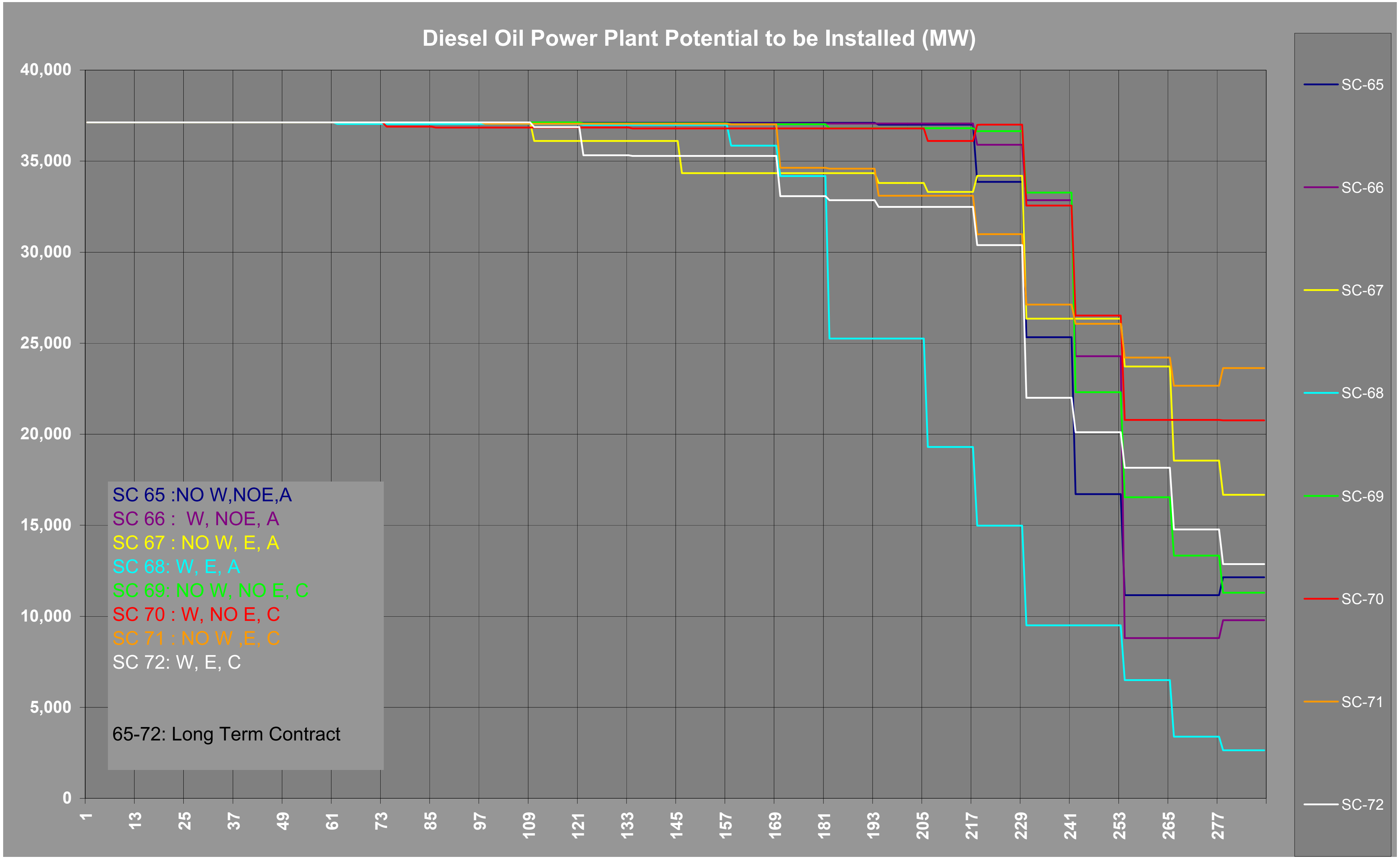
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48



Diesel Oil Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
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169
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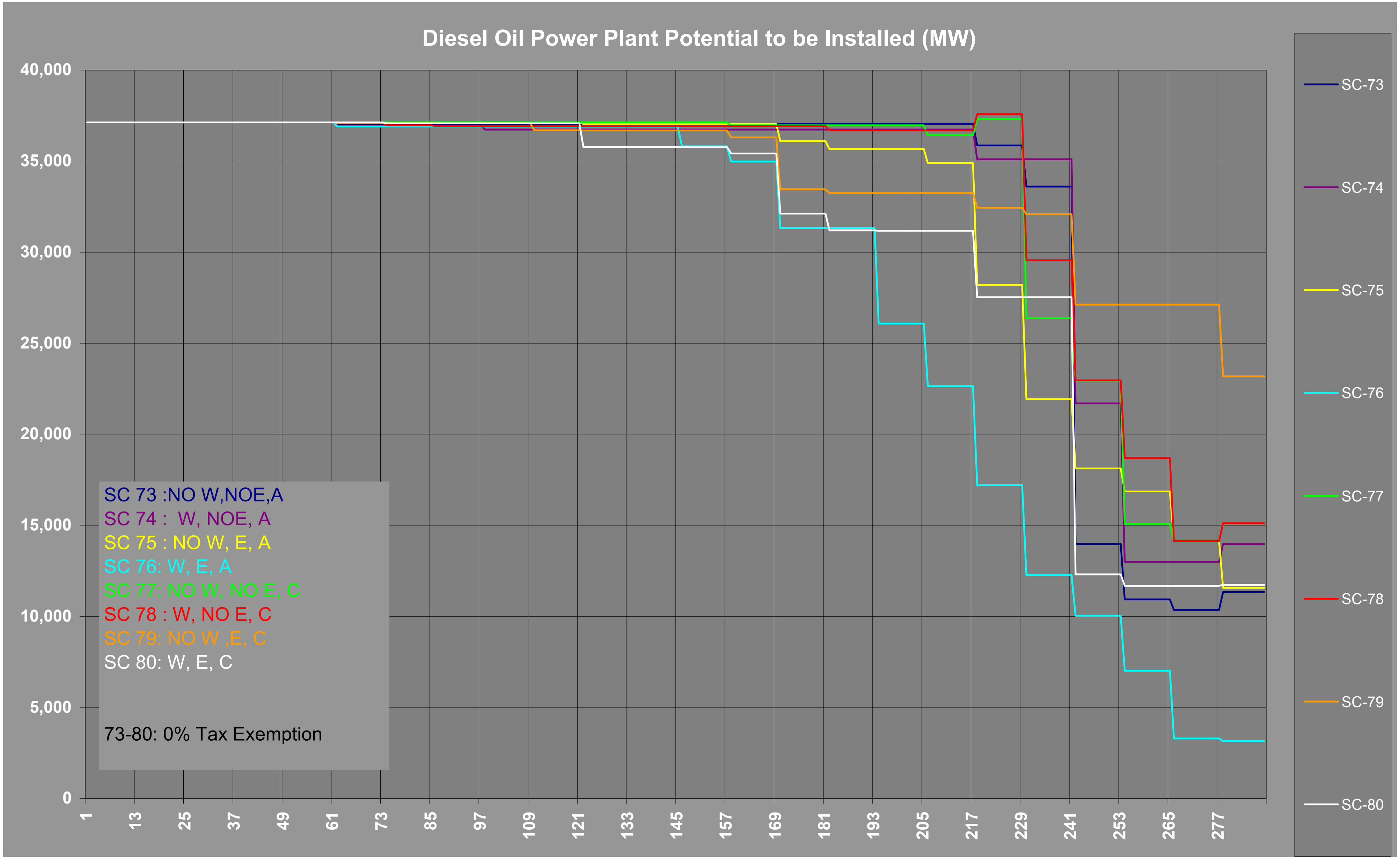
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72



Diesel Oil Power Plant Potential to be Installed (MW)
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1
13
25
37
49
61
73
85
97
109
121
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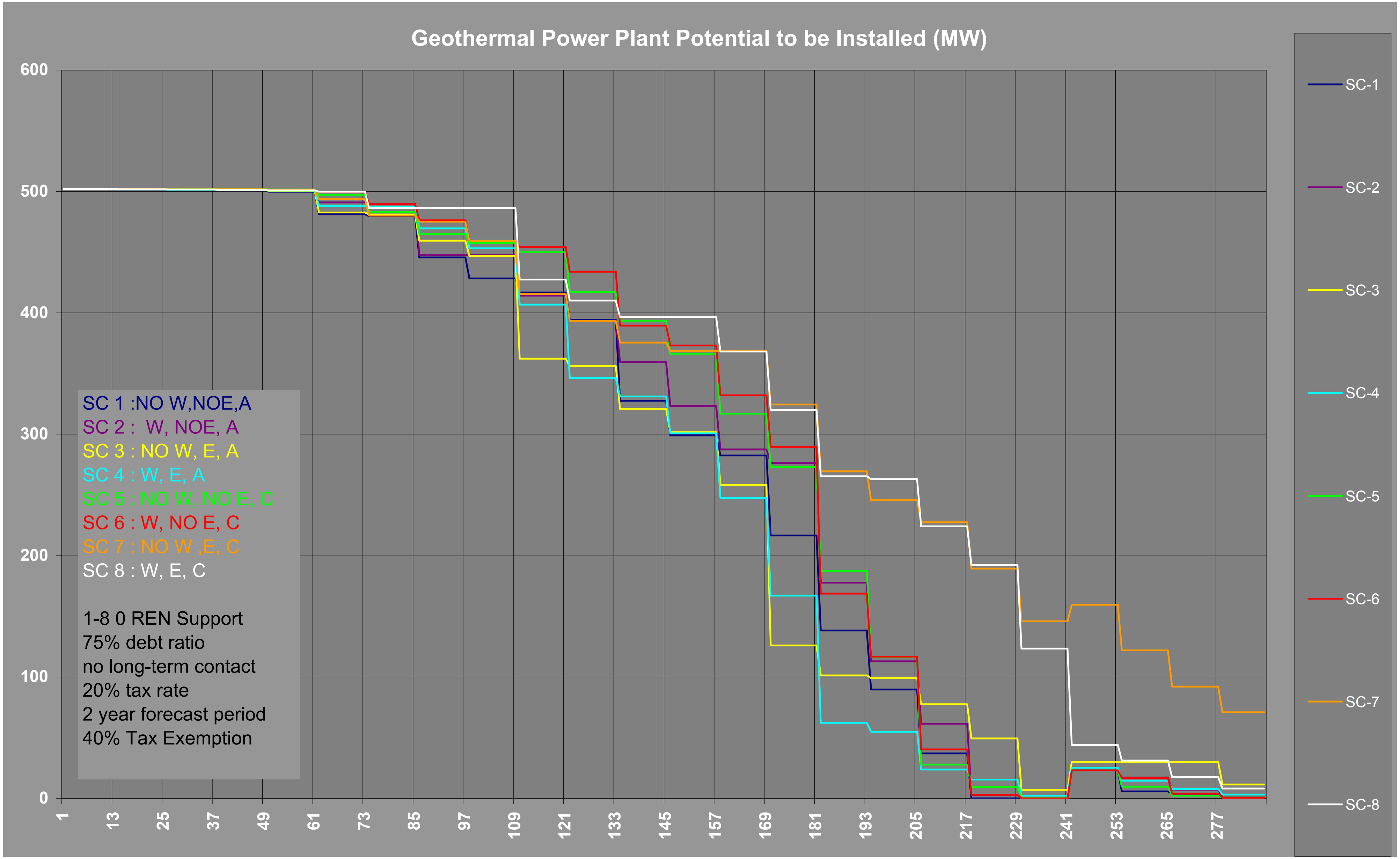
145
157
169
181
193
205
217
229
241
253
265
277
SC 73 :NO W,NOE,A
SC 74 : W, NOE, A
SC 75 : NO W, E, A
SC 76: W, E, A
SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption
SC-73
SC-74
SC-75
SC-76
SC-77
SC-78
SC-79
SC-80



Geothermal Power Plant Potential to be Installed (MW)
600
500
400
300
200
100
0
1
13
25
37
49
61
73
85
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109
121
133
145
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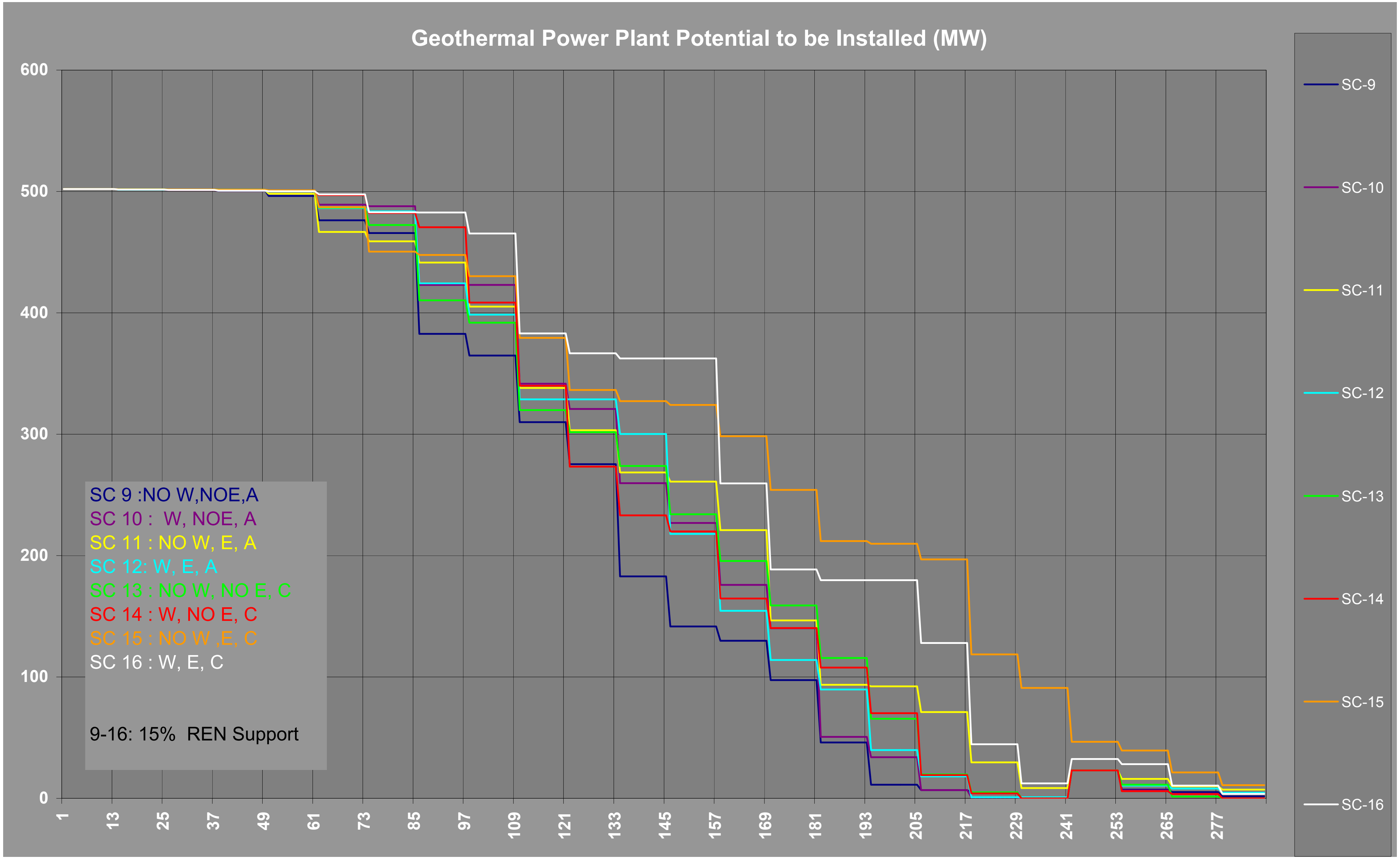
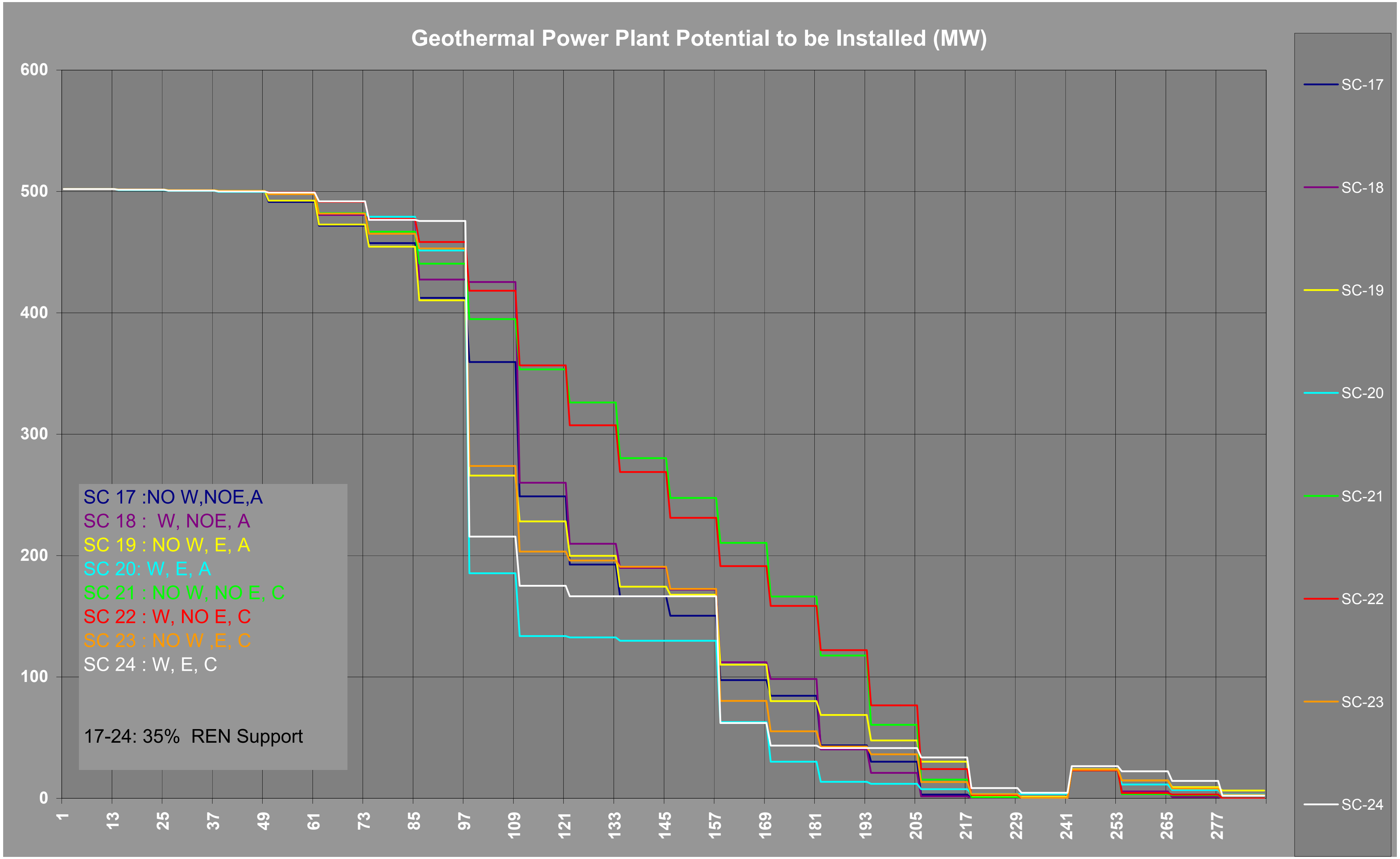
169
181
193
205
217
229
241
253
265
277
SC 1 :NO W,NOE,A
SC 2 : W, NOE, A
SC 3 : NO W, E, A
SC 4 : W, E, A
SC 5 : NO W, NO E, C
SC 6 : W, NO E, C
SC 7 : NO W ,E, C
SC 8 : W, E, C
1-8 0 REN Support
75% debt ratio
no long-term contact
20% tax rate
2 year forecast period
40% Tax Exemption
SC-1
SC-2
SC-3
SC-4
SC-5
SC-6
SC-7
SC-8



Geothermal Power Plant Potential to be Installed (MW)
600
500
400
300
200
100
0
1
13
25
37
49
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC 9 :NO W,NOE,A
SC 10 : W, NOE, A
SC 11 : NO W, E, A
SC 12: W, E, A
SC 13 : NO W, NO E, C
SC 14 : W, NO E, C
SC 15 : NO W ,E, C
SC 16 : W, E, C
9-16: 15% REN Support
SC-9
SC-10
SC-11
SC-12
SC-13
SC-14
SC-15
SC-16


Geothermal Power Plant Potential to be Installed (MW)
600
500
400
300
200
100
0
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37
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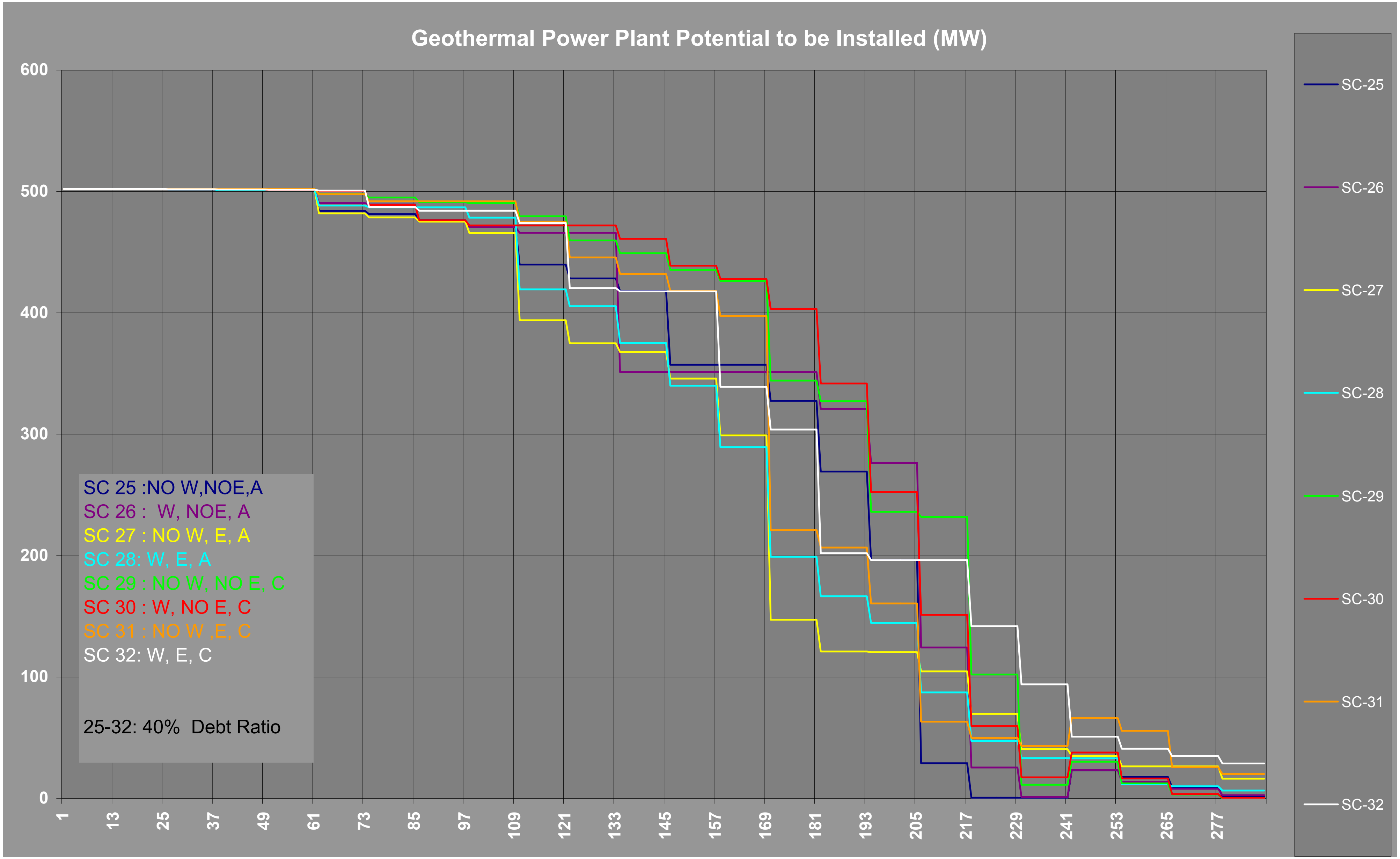
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-17
SC-18
SC-19
SC-20
SC-21
SC-22
SC-23
SC-24
SC 17 :NO W,NOE,A
SC 18 : W, NOE, A
SC 19 : NO W, E, A
SC 20: W, E, A
SC 21 : NO W, NO E, C
SC 22 : W, NO E, C
SC 23 : NO W ,E, C
SC 24 : W, E, C
17-24: 35% REN Support



Geothermal Power Plant Potential to be Installed (MW)
600
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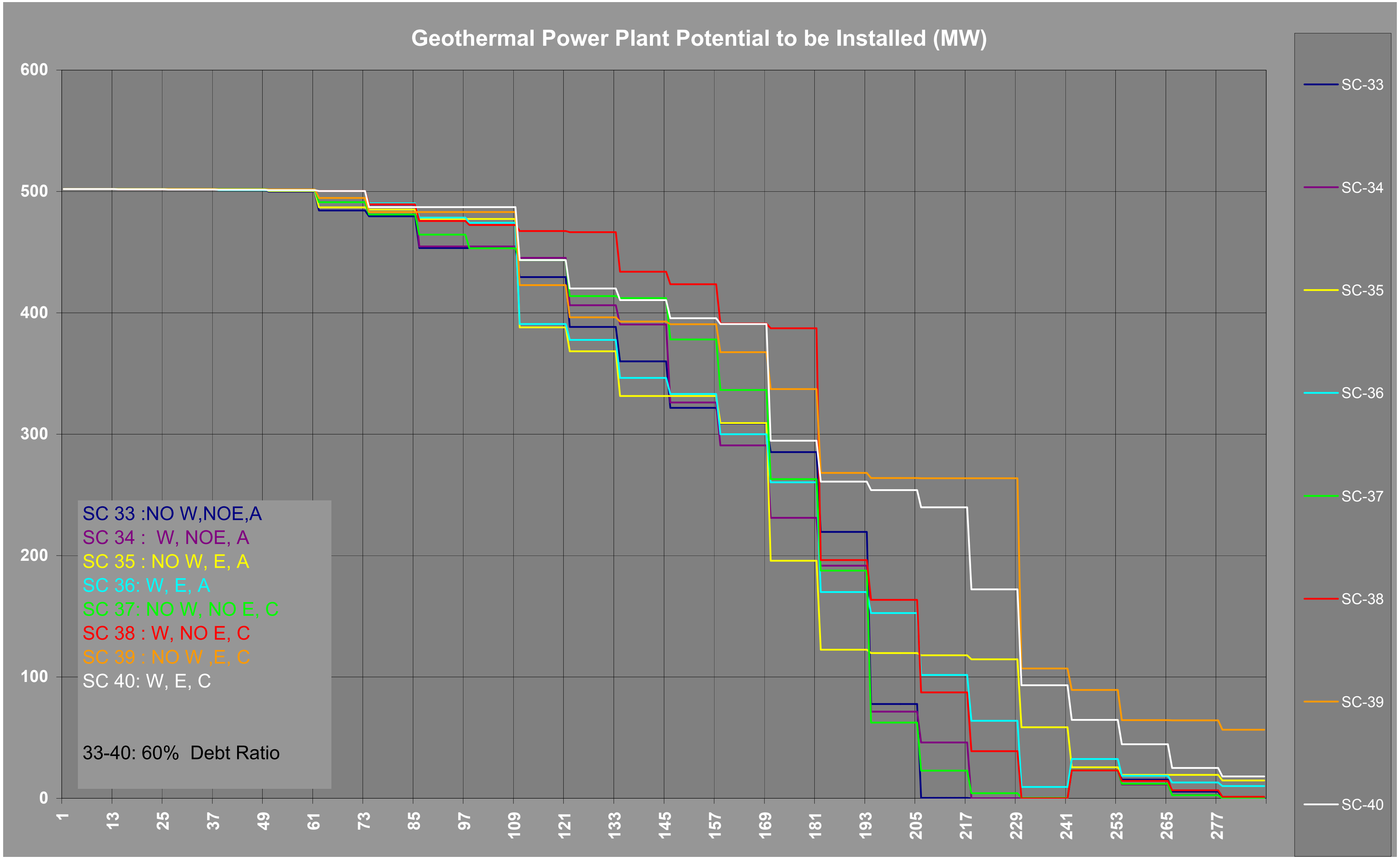
169
181
193
205
217
229
241
253
265
277
SC 25 :NO W,NOE,A
SC 26 : W, NOE, A
SC 27 : NO W, E, A
SC 28: W, E, A
SC 29 : NO W, NO E, C
SC 30 : W, NO E, C
SC 31 : NO W ,E, C
SC 32: W, E, C
25-32: 40% Debt Ratio
SC-25
SC-26
SC-27
SC-28
SC-29
SC-30
SC-31
SC-32



Geothermal Power Plant Potential to be Installed (MW)
600
500
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300
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100
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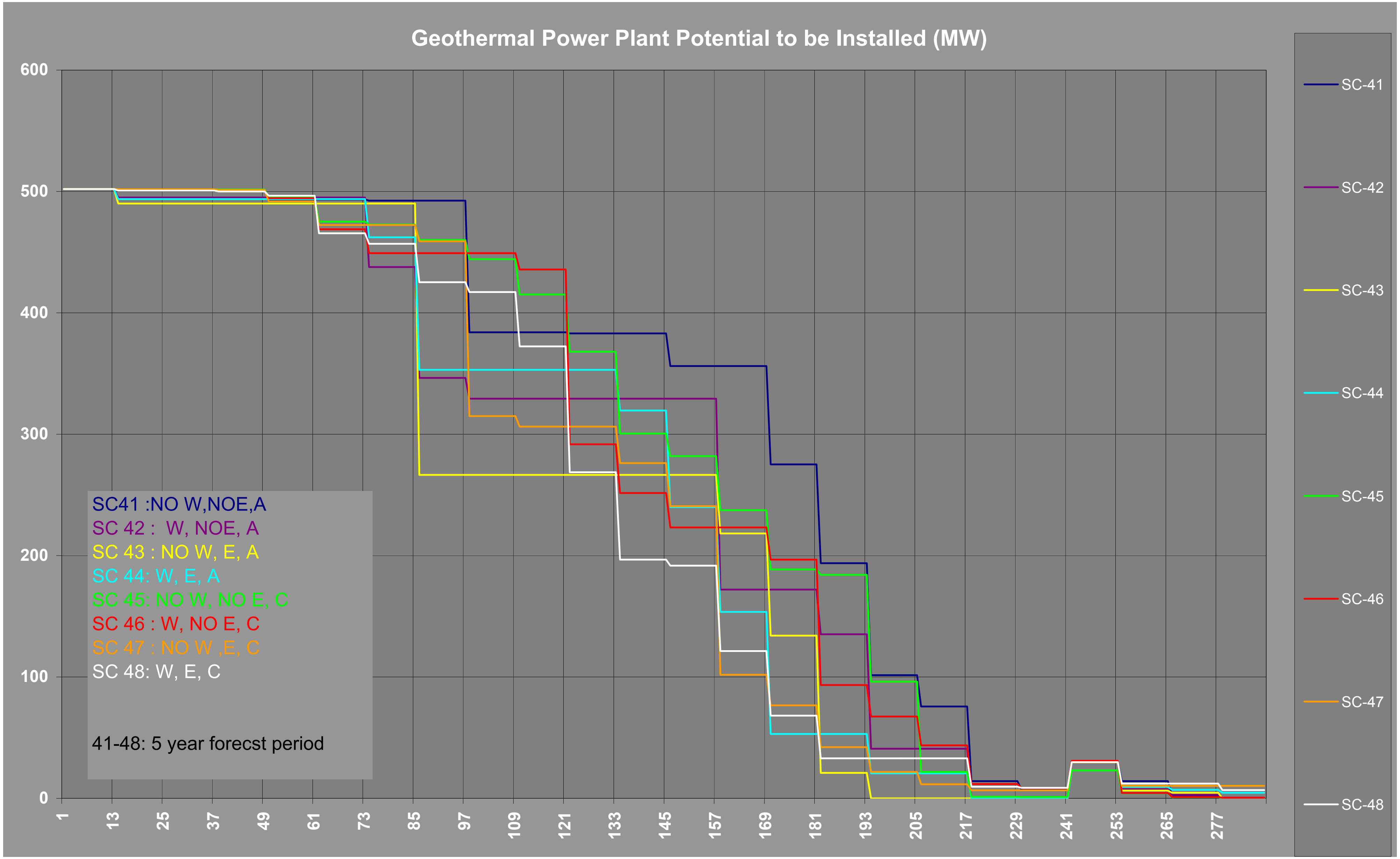
61
73
85
97
109
121
133
145
157
169
181
193
205
217
229
241
253
265
277
SC-33
SC-34
SC-35
SC-36
SC-37
SC-38
SC-39
SC-40
SC 33 :NO W,NOE,A
SC 34 : W, NOE, A
SC 35 : NO W, E, A
SC 36: W, E, A
SC 37: NO W, NO E, C
SC 38 : W, NO E, C
SC 39 : NO W ,E, C
SC 40: W, E, C
33-40: 60% Debt Ratio


Geothermal Power Plant Potential to be Installed (MW)
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121
133
145
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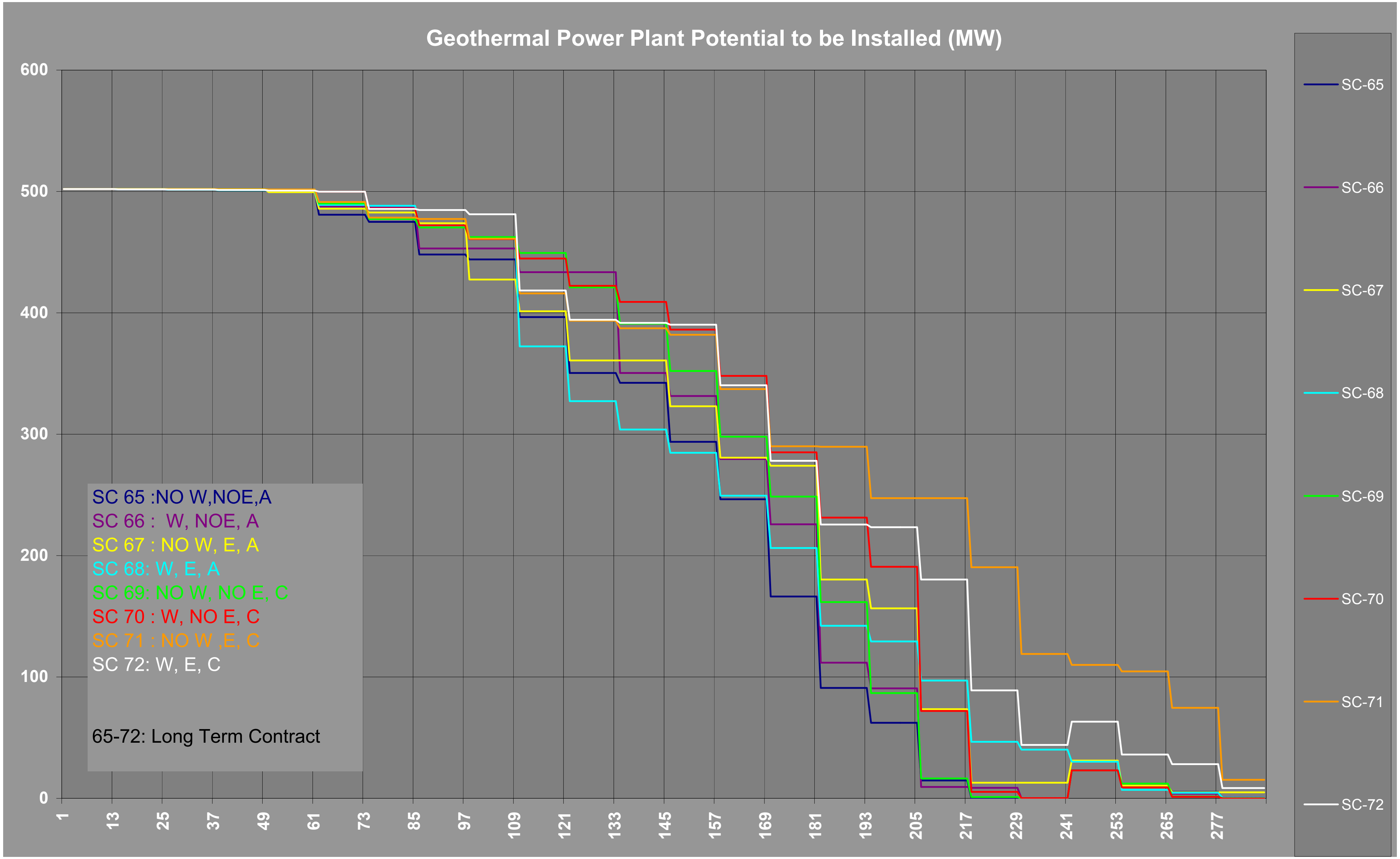
169
181
193
205
217
229
241
253
265
277
SC-41
SC-42
SC-43
SC-44
SC-45
SC-46
SC-47
SC-48
SC41 :NO W,NOE,A
SC 42 : W, NOE, A
SC 43 : NO W, E, A
SC 44: W, E, A
SC 45: NO W, NO E, C
SC 46 : W, NO E, C
SC 47 : NO W ,E, C
SC 48: W, E, C
41-48: 5 year forecst period


Geothermal Power Plant Potential to be Installed (MW)
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100
0
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169
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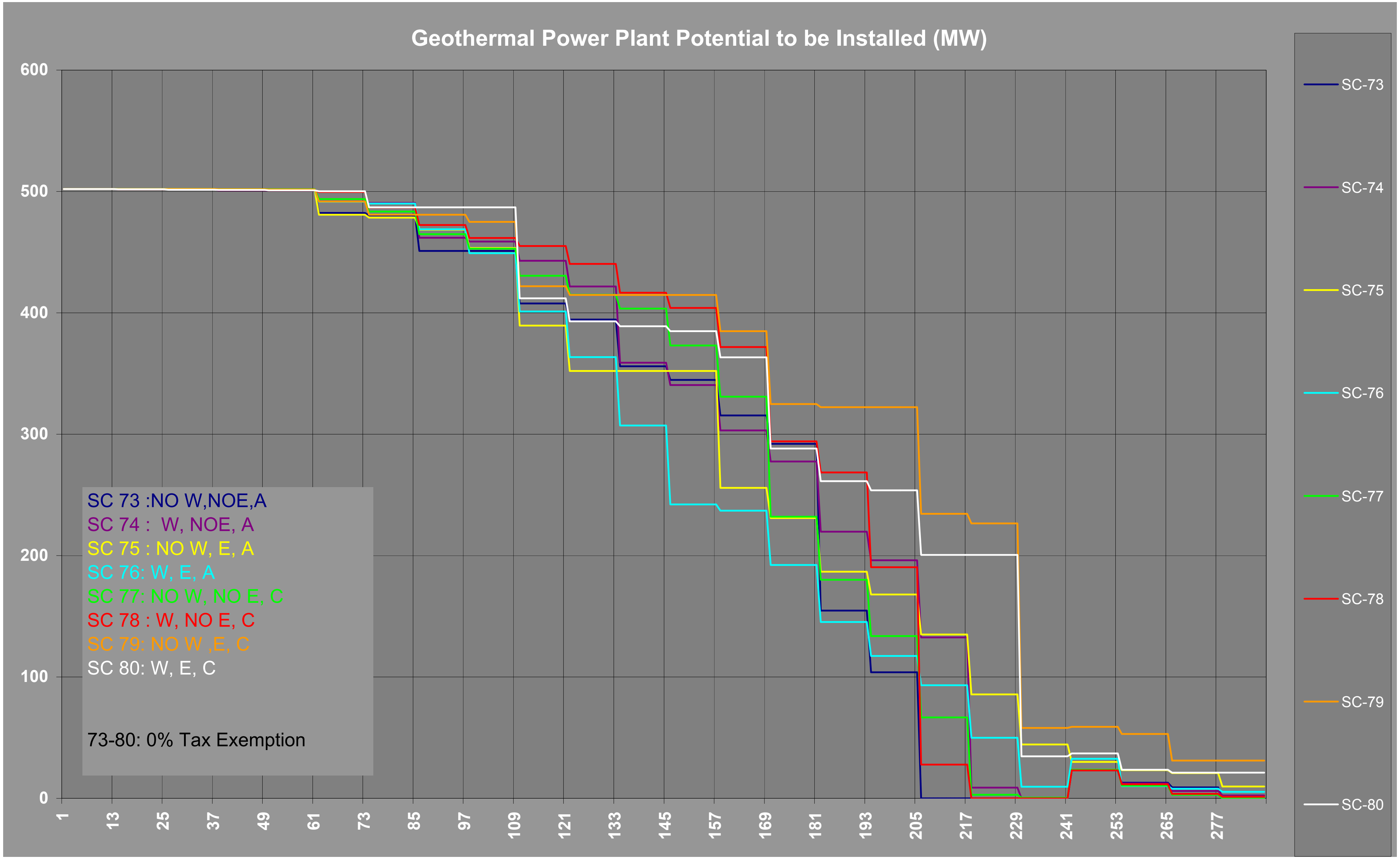
193
205
217
229
241
253
265
277
SC 65 :NO W,NOE,A
SC 66 : W, NOE, A
SC 67 : NO W, E, A
SC 68: W, E, A
SC 69: NO W, NO E, C
SC 70 : W, NO E, C
SC 71 : NO W ,E, C
SC 72: W, E, C
65-72: Long Term Contract
SC-65
SC-66
SC-67
SC-68
SC-69
SC-70
SC-71
SC-72


Geothermal Power Plant Potential to be Installed (MW)
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SC-73
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SC-75
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SC 77: NO W, NO E, C
SC 78 : W, NO E, C
SC 79: NO W ,E, C
SC 80: W, E, C
73-80: 0% Tax Exemption