NOGA Market Clearing Price Analysis

Improvements of the MCP approach

August 2024

DISCLAIMER

This report (the "report" or "presentation") has been prepared by FTI France SAS (“FTI”, trading under “Compass Lexecon”) and N-SIDE (“Consultants”) for NOGA (the “Client” or "Noga") under the terms of the Purchase Order No. PO-003060 (the “Contract”).
No representation or warranty of any kind (whether express or implied) is given by Consultants to any person (except to the Client under the relevant terms of the Contract) as to the accuracy or completeness of the presentation.

The information in this document is provided on an “as-is” basis without any further warranties. Consultants hereby disclaim all expressed and implied warranties.

The report contains information obtained or derived from a variety of sources. Consultants do not accept any responsibility for verifying or establishing the reliability of those sources or verifying the information so provided.

Consultants accept no liability or duty of care to any person (except to the Client under the relevant terms of the Contract) for the content of the presentation. Accordingly, Consultants disclaim all responsibility for the consequences of any person (other than the Client on the above basis) acting or refraining to act in reliance on the presentation or for any decisions made or not made which are based upon such presentation. Nothing in this material constitutes investment, legal, accounting or tax advice, or a representation that any investment or strategy is suitable or appropriate to the recipient’s individual circumstances, or otherwise constitutes a personal recommendation. While Consultants consider that the information and opinions given in this work are sound, all parties must rely upon their own skill and judgement when making use of it.
The report is based on information available to Consultants at the time of drafting and does not take into account any new information which becomes known to Consultants after the date of the report. We accept no responsibility for updating the presentation or informing any recipient of the presentation of any such new information.
All copyright and other proprietary rights in the presentation are the sole property of Noga and all rights are reserved. The intellectual property rights over the report are to be kept with Noga and shall not be transferred. Nothing in this document shall be construed as granting, by implication or otherwise, any license with respect to its content or part thereof, or with respect to know-how or other intellectual property rights included or mentioned.

All the disclaimers above will be read as if Noga was specifically mentioned alongside with Consultants.

Executive Summary

The ongoing reforms of the Israeli electricity market and current settlement rules using wholesale prices are increasing the importance of price formation for market participants.
In this context, in May 2022, NOGA has contracted Compass Lexecon and N-SIDE to analyze and provide recommendations to revise the current MCP (former SMP – System Marginal Price) calculation rules that are currently in place in the Israeli power market.

The objective of analyzing the current MCP algorithm and potential alternatives is to improve existing pricing methodology from a modelling and algorithmic standpoint providing model-based validation of the considered options.
More specifically, the study aims at improving the efficiency of the price signal and reducing the need for make-whole payments, which compensate losses that market participants would otherwise face if final settlements were only depending on MCPs and dispatch levels.
Efficient market monitoring must be implemented in the market, in order to enforce market rules and prevent an increase of make-whole payments, no matter the chosen pricing rule.

The analysis has identified gaps in the current approach to calculate the market price:

- The current MCP calculation approach is **inspired by the standard marginal pricing** but departs from it because the MCP in a given half-hour does not properly reflect the incremental system cost to serve one additional MW of load at that period.
- The current pricing business rules that select the cheapest partially loaded unit do not properly define which units are "partially loaded" (unbinding method) because ramp conditions and other technical constraints (such as reserve provision) may be overlooked during the calculation of prices.
- The current MCP calculation also overlooks the intertemporal constraints that may originate, for example, from ramp conditions or from the operation of pumped hydro storage units (size of the reservoir implicitly constraining the volume of energy that can be pumped over multiple periods).
- As a result, current MCP (based on 2021 analysis) is on average 18% to 19 % lower than the MCP that would be obtained with a standard marginal pricing calculation.
- The current pricing methodology does not reflect commitment costs such as minimum load costs and start-up costs.
- Furthermore, current market clearing prices are calculated using an "unconstrained" model which is derived from the main dispatch run model by dropping specific requirements. Since the current MCP calculations are based on a modified version of the main dispatch run model, prices may further depart from standard marginal prices that are fully coherent with the actual dispatch.
- The current pricing methodology does not reflect the impact of downward bids (i.e. bids to reduce the output) and renewables curtailment on price calculation.

- The current MCP approach has no transparent reserve price in the current market design in Israel. The missing reserve market is currently replaced by Lost Opportunity Costs payments to resources subject to the pay-as-clear regime that are held back for providing reserves.

Three main corrective measures to address the above issues are proposed in this study:

1. Compute the MCP based on standard marginal pricing, by retrieving the so-called "shadow price" (optimal dual variable value) of the system balance constraint for each half-hour. These shadow prices correspond to optimal prices which properly reflect, for each half-hour, the incremental system cost for serving one additional MW of load (assuming that the commitment status, i.e., the "on/off" status, of each unit, is not allowed to change in the pricing run, if needed). They also ensure that units have no economic incentive to deviate from the dispatch that is calculated in the dispatch run.
2. Keep, to the extent possible, all constraints and features of the main dispatch run (constrained model including system operation constraints, such as network and fuel constraints) in the pricing run (unconstrained model) and allow discrepancies only in case of well-identified business or political reasons. The underlying principle is that the pricing should in general reflect in the most precise way the value of electricity based on the incremental costs, and the true incremental costs can only be reflected if the real operating conditions are properly reflected in the models.
3. Strive to better reflect commitment costs, such as start-up and no-load costs in the MCP and further lower the make-whole payments. The "integer relaxation approach" is considered since it approximates well the so-called "convex hull prices". Convex hull prices minimize the impact of non-convexities in terms of lost opportunity costs (missed revenues) or losses to compensate via make-whole payments when a unit operates at higher costs than what the MCPs allow it to recover. The intuition of the integer relaxation methodology is as follows: the same standard marginal pricing principles are used, but applied to a pricing run where (a) binary commitment decisions are allowed to take on fractional values (e.g., a minimum load level is enforced only at 60%), and (b) costs associated to these commitment decisions are treated as "variable costs" which depend on the percentage of acceptance of the decision, and can be interpreted as "adders" to what is otherwise setting the MCP.

Simulations of the Israeli market based on 2021 period suggested that:

- Both **standard marginal pricing** and (approximate) **convex hull pricing** lead to MCPs **close to each other on many simulation days**. However, they differ by a large amount in some periods of specific days. For that reason, the average approximate convex hull prices turn out to be substantially higher than the average marginal prices, leading to lower make-whole payments but higher total settlements as the end effect. Lower start-up costs and/or minimum load costs would reduce the difference between the two pricing approaches.
- Standard marginal pricing, compared to (approximate) convex hull pricing, is easier to interpret since there is no need to understand how costs associated

to the binary commitment decisions (startup costs, etc), which are allowed to be fractionally accepted in the pricing run, add to the marginal system costs to form the MCP.

This leads to our proposal to compute MCPs based on standard marginal pricing principles, relying on so-called shadow prices (or optimal dual variables/Lagrangian multipliers) of the system balance conditions.

The simulation of the proposed marginal pricing and the current NOGA's pricing approaches in the forward period 2024-2026 suggested that:

- The proposed marginal pricing approach results in the wholesale electricity prices being on average between 39 and 42$/MWh while the current approach used by NOGA results in prices around 30$/MWh.
- The main differences occur in high demand periods (January and summer months), when, due to the limit on the daily gas consumption, more expensive gasoil units are needed to cover the demand.
- Results show that marginal pricing reduces make-whole payments compared to NOGA's current pricing method.
- Finally, the results suggest only a slight increase in the total procurement costs in the marginal pricing approach as compared to the current NOGA's approach.

Table Of Contents

1 Introduction

The current Israeli electricity market involves a diversity of agents and associated remuneration schemes. These include market participants settled using the market clearing price, other participants paid following a cost-based or a pay-as-bid principle, a centrally operated pumped hydro storage facility and several other entities (for example renewables paid by different tariffs and cogeneration units).

The day-ahead operational planning is developed by NOGA in-house and relies on unit commitment and economic dispatch models. The provision of ancillary services (spinning reserves only) is also accounted for in the dispatch and operation even though it is currently not remunerated in the short-term markets.

Two different pricing models are employed at each stage of the calculation of electricity market prices:

- a constrained version of the daily commitment and dispatch is applied in order to achieve a faithful representation of the system constraints, and
- an unconstrained model is used as a basis for the calculation of MCP.

Settlement of the IPPs operating under the pay-as-clear regime involves compensation from the Market operator in case their total operating cost is greater than the payment collected from MCP.

1.1 Current Market Clearing Operation Processes

The current set of operations that are executed in the day-ahead and real-time electricity markets is presented in Figure 1. As it can be observed in the figure, both the day-ahead and the real-time electricity markets in Israel are based on solving two different optimization programs:

- The first program, called the ***constrained model***, is used for operation, and produces the planned schedule of assets for day-ahead operation and real-time ex-post analysis. Market prices are also computed based on the constrained model at the day-ahead and real-time stage but are not used in practice for settlements.
- In a second phase, the ***unconstrained model*** is a subsequent scheduling model which is only used for the computation of the actual day-ahead and real-time market clearing price[1].

In practice, these two optimization programs correspond to a unit commitment problem with a granularity of 30 minutes, which optimizes energy while ensuring that a minimum level of spinning reserve is available both upwards and downwards for operation even

[1] 2024 market clearing in real-time is not yet operational.

though procurement of reserve is not priced. This unit commitment problem differs between the two models, since the two models do not account in practice for the same constraints regarding the Israeli power system.
Here is a list of the different constraints that are not included in the unconstrained model:

- *Transmission constraints*: Limiting or allowing the production of different assets due to limits on the transmission network.
- *Gas system constraints:* The amount of available natural gas over a day or an hour for the entire Israeli system is limited, thereby restricting the possible amount of electric power that can be produced by natural gas units.
- *Backup fuel usage:* Some units have the possibility to run on two different fuels so that, when a shortage of natural gas occurs, these dual units can provide electric power using their backup fuel. This constraint is not necessary in the unconstrained setting, since no shortage of gas can be observed because of the removal of the previous constraint.
- *Unit tests*[2]*:* Dual fuel units, that have the possibility to operate on two different fuels (for example: primary fuel is gas and secondary fuel is gasoil), need to perform a test by running on their dual fuel for a few hours. These tests are accounted for in the constrained model, whereas, in the unconstrained model, dual fuel units are considered to operate on gas only.
- *Environmental constraints:* These constraints limit the production of certain units due to environmental limits such as restrictions on CO_2 emissions in a particular region.

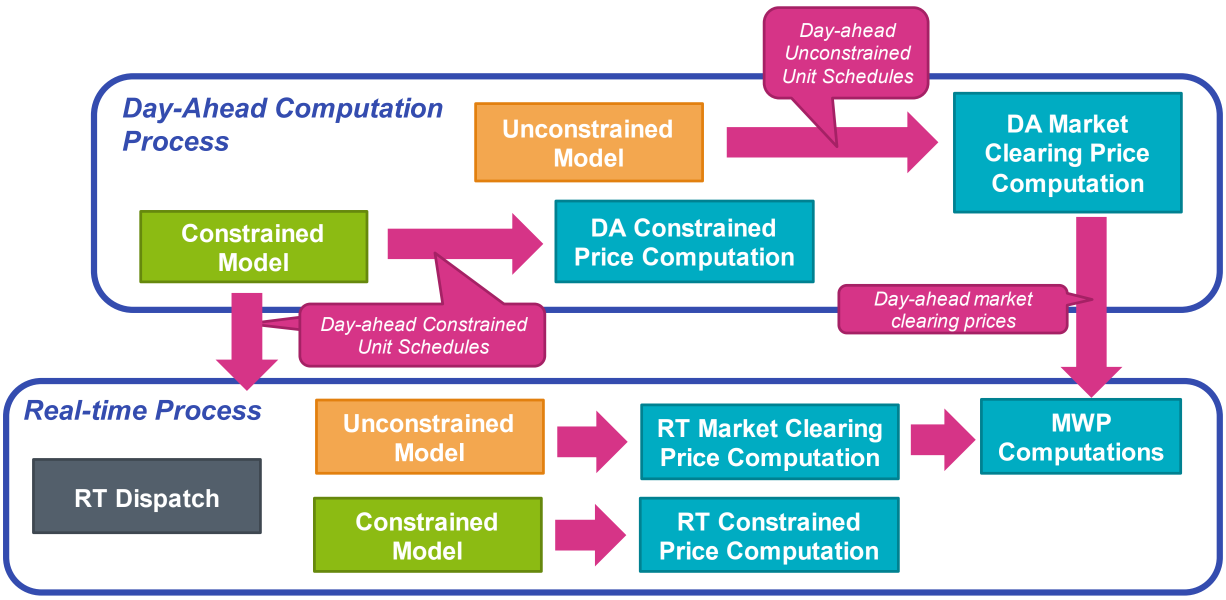


Figure 1: Current set of processes put in place in Israel for day-ahead and real-time electricity market operations, clearing and settlements.

With respect to the Israeli power system, the current set of operations that are in place, starting from the day-ahead stage, is split into three different phases that are

[2] Note that this constraint remains in the unconstrained model for units which are pre-commercial or for units that have undergone maintenance or outage.

characterized by different computations. This is depicted in Figure 1 and further detailed in the sequel.

- **Day-ahead:** During this period, three calculations are conducted in order to operate and clear the day-ahead electricity market:
  - *Day-ahead Constrained Model:* First, the constrained model is used to produce the day-ahead schedule that is actually used in practice for operations.
  - *Day-ahead Constrained Price Computation:* Market clearing prices are computed based on the schedules provided by the day-ahead constrained model. The process used to compute these prices is the same as the one detailed in the "Day-ahead Market Clearing Price Computation" bullet point used to compute the prices based on the unconstrained schedules. These prices are not used in practice for settlements but are published by NOGA for transparency.
  - *Day-ahead Unconstrained Model:* The unconstrained model is then executed to obtain a new day-ahead schedule. This model is not used for operation, but instead for computing the day-ahead market clearing prices via the next process.
  - *Day-ahead Market Clearing Price Computation:* Finally, the day-ahead market clearing price is computed based on the schedule resulting from the day-ahead unconstrained model. The market clearing price is computed by first gathering all the units that can still contribute by one more MW and then by observing the difference between their current load and their maximum capacity. The market clearing price is determined as the marginal cost of the cheapest unit in this group.

- **Real time:** During this period, unit dispatches and commitments are modified in real time by NOGA operators in order to respect real-time operational constraints, and to match the realized renewable production and system demand.
- **Post Real-time:** During this time period, four different steps are performed:
  - *Real-time Constrained Model:* The constrained model is executed to produce a new schedule which accounts for the realized renewable production and system demand along with additional real-time operational constraints and availability of units. This model's input is based on the schedules of the Day Ahead constrained model. Each unit's starting position is the load calculated in the Day Ahead schedule, while its availability is based on real-time data.
  - *Real-time Constrained Price Computation:* Market clearing prices are computed based on the schedules provided by the real-time constrained model. The process used to compute these prices is the same as the one detailed in the "Day-ahead Market Clearing Price Computation" bullet point used to compute the prices based on the day-ahead unconstrained schedules. These prices will not be used in

practice for settlements but will be published by NOGA for transparency.

- *Real-time Unconstrained Model:* A real-time unconstrained schedule is provided by the unconstrained model, which accounts for the realized renewable production and system demand in real-time along with additional real-time operational constraints and real-time availability of units. This model's input is based on the schedules of the Day Ahead constrained model. Each unit's starting position (including commitment) is the load that was calculated in the Day Ahead schedule, while its availability is based on real-time data.

- *Real-time Market Clearing Price Computation:* Based on the real-time unconstrained schedule that is obtained in the previous step, the real-time market clearing price is computed in the same spirit as the day-ahead one.

- *Computation of Make-Whole Payments and Settlements:* Finally, make-whole payments are computed for pay-as-clear units (central-dispatch only) using the two constrained schedules and market clearing prices of the unconstrained models (day-ahead and real-time).

1.2 Current Approach towards Computing Make-Whole Payments

Make-whole payments are currently used in Israel only for IPP units that operate under a pay-as-cleared setting (but not for self dispatched generators). These units receive a strictly positive compensation from the Market Operator if their total operating cost is greater than the payment that is collected from the system operator for their daily energy. The daily operational cost of a unit is expressed as:

$$OC_g = \sum_{t=1}^{48} \left(MLC_{g,t} + GC_{g,t}^{DA} + GC_{g,t}^{RT} \right) + SC_g$$

In this expression, OC_g represents the total daily operational costs incurred by unit g. The minimum load cost of unit g at time period t is given as $MLC_{g,t}$. Start-up costs incurred over the clearing horizon are represented by SC_g. Finally, the day-ahead and real-time generation costs that are incurred (variable costs and costs linked to heat rate and fuel price) are respectively represented by $GC_{g,t}^{DA}$ and $GC_{g,t}^{RT}$. The total payment over a day, which is received by a unit, is described by the following expression:

$$RP_g = \sum_{t=1}^{48} \left(E_{g,t}^{DA} \cdot MCP_t^{DA} + CP_{g,t}^{DA} + \left[E_{g,t}^{RT} - E_{g,t}^{DA} \right] \cdot MCP_t^{RT} + CP_{g,t}^{RT} + LOC_{g,t}^{RT} \right)$$

The received payment by unit g (RP_g) is therefore defined as the sum of several components:

- $E_{g,t}^{DA} \cdot MCP_t^{DA}$: Payment for the generated day-ahead energy computed using the day-ahead market clearing price;
- $CP_{g,t}^{DA}$: Complementary day-ahead payment if day-ahead generation costs are not fully covered by the previous term;
- $\left[E_{g,t}^{RT} - E_{g,t}^{DA}\right] \cdot MCP_t^{RT}$: Payment for the extra real-time energy generated above the scheduled day-ahead energy. It is computed using the real-time market clearing price;
- $CP_{g,t}^{RT}$: Complementary real-time payment if real-time generation costs are not fully covered by the previous term (same principle as the second term for day-ahead);
- $LOC_{g,t}^{RT}$: Real-time lost opportunity cost which represents the energy offered but not purchased even though the market clearing price is higher than the offered price times the difference between the real-time market clearing price and the offered price corresponding to the "paradoxically rejected" energy offered.

Finally, having expressed both the operational costs and the received payments of a given unit, we can provide the complete expression used to compute the make-whole payments that are received by a unit g:

$$MWP_g = \max\{OC_g - RP_g | 0\}$$

2 Identified gaps in the current Israeli pricing method and MCP recommendations

The current pricing approach used by NOGA is inspired from standard marginal pricing. However, it does not precisely apply marginal pricing principles and the actual business rules correspond to standard marginal pricing only in the simplest market setups.

For example, when searching for the cheapest partially loaded unit to set the MCP, some units are considered as "partially loaded" in a given period because they produce below their maximum capacity, even though they cannot produce more at that period due to their ramp conditions and their production at the previous period. As a result, market clearing prices could be too low, leading to high make-whole payments compensating for the losses that the units would face if settlements were only based on the MCP and dispatch levels.

Also, MCP calculations do not currently consider the reserve requirements, implicitly assuming that there is no resource limitation to provide reserve (or equivalently that there is no reserve requirement).

Other challenges pertain to the different calculations currently run by NOGA, one dispatch run based on a “constrained model” to calculate dispatch levels of the units, and a second “unconstrained run” for pricing purposes.

The analysis of the best pricing principles applicable in the Israeli context revolves around three pillars.

- **Marginal pricing fixes:** Implementing a pricing solution resulting in Optimal Pricing, which produces prices that are consistent with the optimal dispatch of the system. These prices correspond to the incremental costs of energy, as computed at the optimal dispatch. These prices thus reflect all the dispatch constraints, in contrast to the approximate business rules. Such a pricing methodology, for example, does *not* consider a unit to be partly loaded if technical constraints would prevent it from producing more, and properly consider the impact of the reserve requirements on the true incremental costs of energy, acknowledging that reserve provision is bounded (i.e., that the reserve available in the system may be limited, having an impact on the incremental cost of energy).

- **Constrained versus unconstrained models:** This element adds practical and political aspects to the previous pillar by considering the benefits of accounting for specific dispatch constraints while computing the MCP.

- **Non-convexities:** This stream includes an aspect of how to manage non-convexities to the two previous discussions (e.g. in order to account for the impact of start-up/minimum load costs on the MCP). The rationale for tackling non-convexities separately is that previous recommendations on “constrained versus unconstrained” and on using “optimal pricing principles” still apply, regardless of the specific approach that is chosen for pricing the non-convexities.

The sum of these three aspects therefore tackles virtually all the different aspects that pertain to pricing.

2.1 Marginal pricing fixes

2.1.1 Optimal price principles

Pricing must be consistent with dispatch instructions. The **dispatch** is **optimal** when units are dispatched so as to serve demand at <u>minimum cost.</u> **Optimal pricing** happens when the price that is paid to units induces them to <u>voluntarily</u> follow the optimal dispatch.

Optimal prices are naturally deduced from the dual variables of the dispatch problem. They are set by the so-called “shadow prices” of the energy (or reserve) balance conditions of each period. These optimal prices are also named optimal Lagrangian multipliers or optimal dual variable values. They reflect the exact marginal cost of energy (or reserve) for every given period of power system operation. They can be interpreted as the incremental (or decremental) cost for the delivery of an infinitesimal increase (or decrease) of demand in a given half-hour taking into account the costs (given via bids or heat rates and fuel costs depending on the unit regulation regime) and all the dispatch constraints. Optimal dispatch and pricing can be integrated in a streamlined sequence of dispatch/price calculations through specialized algorithms, as shown in Figure 2 below.

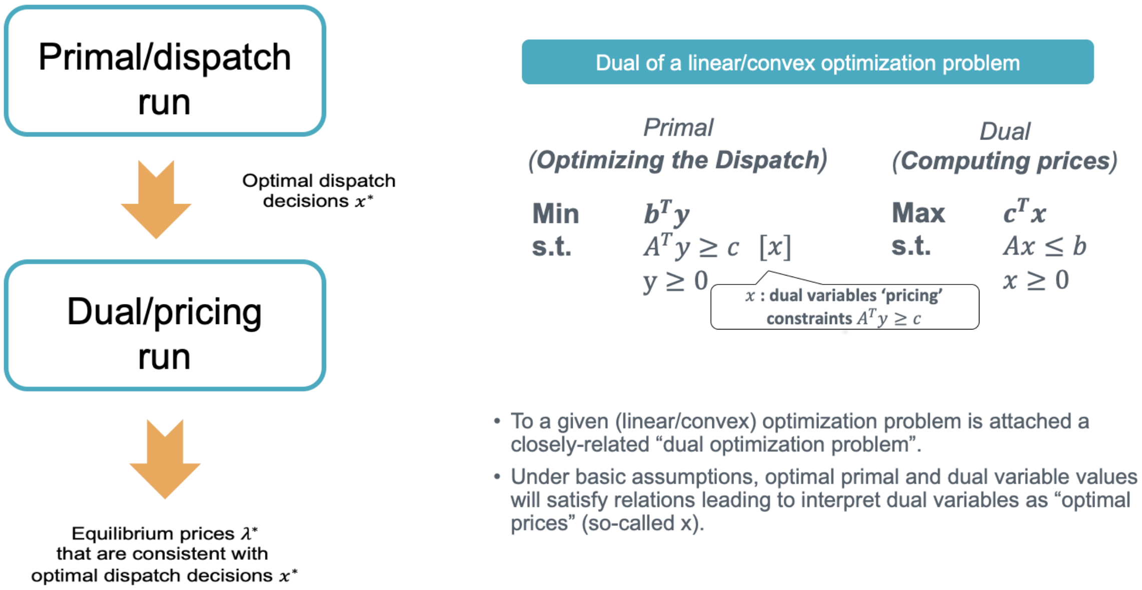


Figure 2: Optimal prices can be computed as the dual multipliers of the primal problem which is used for dispatching the system optimally. They can be computed in a pricing run, which is standard practice in the most advanced EU and US markets

2.1.2 The current pricing methodology of NOGA departs from optimal pricing

NOGA uses business rules for setting the MCP that approximate, but sometimes do not match optimal pricing discussed above. In most cases, optimal pricing can be provided by the assessment of the offer of a marginal plant, the offer of which is partially accepted. This underlies the business rules that NOGA uses for pricing. However, because of the different optimization tradeoffs (e.g., intertemporal constraints, such as ramp constraints or pumped hydro storage) or constraints related to reserves, the optimal price may depart from the marginal cost of a marginal unit.

2.1.3 Inaccurate usage of partly loaded status to define the cheapest marginal unit in the current pricing methodology of NOGA

Using the pricing approach of NOGA, the price is set by the partially loaded plant with the lowest marginal cost, i.e. the cheapest seemingly marginal unit. However, such partially loaded units may actually be partly loaded due to constraints that prevent them from providing additional energy. The fact that some of the seemingly partly loaded units actually cannot produce more would lead to higher prices under an optimal pricing approach. Indeed, NOGA's approach may result in identifying multiple units producing between their technical minimum and maximum due to operational constraints and set the MCP based on the minimum cost of these units.

As a result, differences in prices, such as those observed in Figure 3 below, arise from the fact that, in the pricing approach used by NOGA, the price is set by the partially loaded plant with the lowest marginal cost.

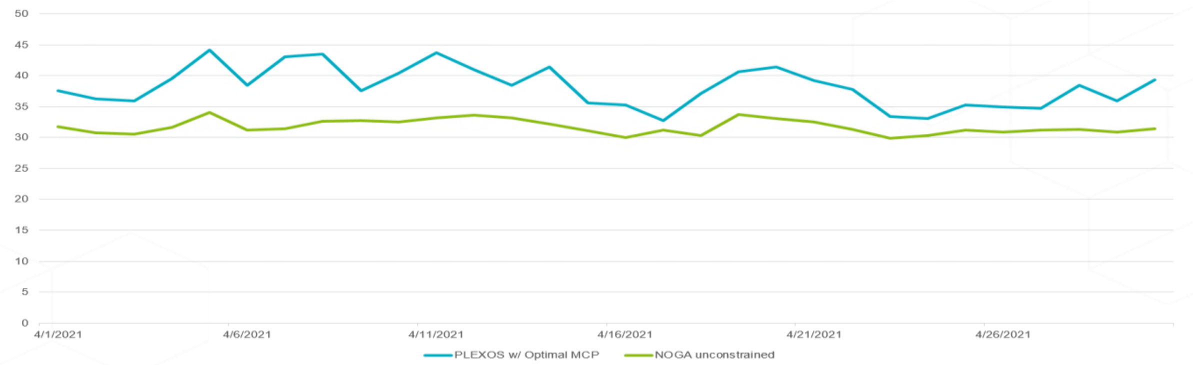


Figure 3: Comparison of average daily prices ($/MWh) obtained for April 2021

2.1.4 Impact of hydro resources on optimal pricing

Another aspect on which the current business rules of NOGA depart from optimal pricing relates to how hydro resources are managed.

Hydro resources allow moving energy around between peak and off-peak periods. The general effect is to obtain prices that are more equalized across time periods.

In the extreme case where hydro has no operational constraints (perfect efficiency with infinite pumping capacity, production capacity, and energy storage capacity), energy prices are guaranteed to be equal throughout the market clearing horizon, allowing to “arbitrage away” any temporal price differences. Put differently, if the price is not constant over time, a perfectly flexible hydro unit could make infinite profit. This result is proven formally in Appendix B, and also developed in mathematical detail in [2].

In the case where hydro has efficiency losses, prices are not equal across periods, but their ratio tracks the efficiency of the pumped hydro storage. This result is also described in Appendix B, and developed in mathematical detail in [2].

The way to address all of the aforementioned issues is to rely on generalized marginal pricing. Generalized marginal pricing can be accomplished by relying on the dual multipliers that are computed from commercial optimization software, when computing the optimal dispatch of the system.

2.1.5 Further departures of NOGA's approach from optimal pricing

Finally, NOGA uses specific business rules that may create further departures from optimal prices, such as the exclusion of coal bids and downward bids from the definition of the MCP. Nevertheless, we note that the exclusion of coal units from price formation may be justified in the Israeli context due to their very specific status.

2.1.6 Properly implementing optimal pricing: conclusions

The proper way to address the issues highlighted above is to replace the current business rules of SMP calculation by setting the MCP at the level of the "shadow price" of the energy balance constraint in each period. These optimal prices are also named optimal Lagrangian multipliers or optimal dual variable values. They reflect the exact marginal cost of energy for every given period of the power system operation unconditionally on the specific business rules to identify part-loaded plants, or without exclusion of specific bids and offers.

2.2 Constrained versus unconstrained models

The Israeli electricity market clearing and operation process currently employs two models, which are referred to respectively as the ***constrained*** and ***unconstrained*** models. Firstly, the constrained version is employed for the purpose of unit commitment and aims at a correct representation of system constraints. Then, the unconstrained model, which is a reduced version of the constrained model, is used as a basis for computing MCP used for settlements.

In this section, the necessity of using these two different models for operation and pricing is assessed.

First of all, **as a general economic principle, dispatch and prices should be as consistent as possible**. This means that it is generally better to compute dispatch and prices by using the same optimization model (i.e., a single calculation that provides fully coherent final prices and dispatch instructions), and this optimization model should represent the true physical constraints of the system. Indeed, this leads to fewer "inconsistencies" in the model outcomes (i.e., when prices are not coherent with the dispatch instructions), which means better economic signals and a reduction of settlement issues (e.g., mismatch between the settlement towards the sellers and the buyers) or gaming issues.

However, despite this general principle, in practice it may be necessary **to depart from full consistency for "political reasons".**

An illustration of this divergence can be found in Germany that operates as a single zone, despite significant internal grid congestions. From a theoretical perspective, a more granular representation of the European electricity grid (via nodal or sub-zonal pricing) would provide better economic signals. However, this is not deemed desirable in Germany and has not been implemented mostly for political reasons. As a consequence, the day-ahead market “ignores” such internal grid congestions and provides a uniform market clearing price throughout Germany. However, the resulting day-ahead dispatch may not be feasible from an intra-zone transmission capacity perspective. This is typically due to a surplus of wind generation in the North of Germany where there is less demand and a deficit of generation in the South of Germany where load is high [8, 9]. The dispatch is then “corrected” in a so-called “redispatching phase” after the day-ahead stage. Such “corrections” instruct the assets to deviate from their best economic schedules given the uniform German prices. “Corrections” are settled based on a regulated so-called “cost+” approach. As a consequence, prices in the German market ignore the internal transmission constraints, while the actual dispatch in real-time takes these constraints into account. This approach leads to substantial economic inefficiency and significant direct “redispatch costs” (i.e., in billions € per annum only for Germany) which need to be recovered outside the market clearing mechanism (i.e., via grid fees in practice).

Furthermore, the departure from full consistency between dispatch and pricing models may induce severe gaming opportunities. Such gaming practices have been observed in both US [10] and European [11] markets, and come under the name INC or DEC gaming. The idea of the DEC game is for agents to alter their bid price when they have been accepted in the day-ahead zonal market, and claim that re-dispatch is costless (or even results in negative costs!). This allows agents to pocket the day-ahead zonal price for offering no energy whatsoever to the system. This strategy was one of the gaming strategies employed by ENRON during the California energy crisis of 2001 (where it was dubbed “Death Star” by ENRON traders [2]), which contributed to the ultimate meltdown of the California market. Another severe effect of zonal pricing is that it fails to induce investment in the locations where the system requires it [12]. In the context of the German example explained above, an adverse effect of zonal pricing is that there are equally strong incentives for investment in the North of the country as there are in the South, despite the clear need of locating new generation capacity in the South.

NOGA’s approach which uses two different optimization programs for operations and pricing is notionally similar to the illustrations above. However, a few key differences with respect to the German case can be highlighted:

- The features that are applied in the constrained program but are “ignored” in the unconstrained clearing are very specific to the Israeli context. They relate not so much to internal transmission congestion but more broadly to non-economic constraints (i.e. that are not expected to provide economic signals for whatever political reasons)
- No “impossible dispatch” is committed at any time since the constrained program is used for operations. Instead, a realistic dispatch may be settled at

prices that are not perfectly coherent, since prices are based on the unconstrained run.

- NOGA's approach may therefore be less susceptible to gaming (compared to the German counterfactual of ignoring some constraints entirely in the day-ahead dispatch, which leads to INC-DEC gaming risks).

From these observations, we consider that the current approach for determining the settlement prices based on the ***unconstrained dispatch*** is an acceptable way to address mandatory non-economic (i.e. political) constraints. Furthermore, it can be observed in Figure 4 that, historically, the constrained and unconstrained prices that were computed by NOGA were relatively similar in practice for year 2021. This observation suggests that the modeling differences between the two types of models do not have a strong impact on the computation of the market clearing prices.

Figure 4: Comparison of the average daily historical constrained and unconstrained market clearing prices [$/MWh]

Going forward, attention should be paid in practice to limit as much as possible the features which are "ignored" in the unconstrained optimization compared to the constrained model in order to keep the prices as consistent as possible with the actual dispatch, therewith providing the best possible economic incentives. Indeed, ignoring features which have material impacts over the clearing prices will inevitably lead to settlement issues. For example, if a severe gas shortage limits the actual generation of gas in the (constrained) dispatch calculation but not in the (unconstrained) price calculation, substantial inconsistencies between the dispatch costs and prices may occur.

On the short term, such inconsistencies imply that the market does not fully self-finance the computed dispatch, which inevitably lead to "indirect costs". In Germany and the EU, these huge "indirect costs" (i.e. redispatch costs in particular) are usually financed through the grid fees of the TSOs. Our understanding is that such "indirect costs" would be recovered through the "NOGA tariff" for the Israeli context.

On the long term, such inconsistencies imply that the market does not receive the correct investment signals, and therefore fails to self-heal [12]. In Germany, the consequence of applying a uniform price despite significant gird congestions implies that investments in wind generation are recurrently placed in the North of Germany (where there is more wind), although generation is more valued in the South, closer to the greater load centers.

In view of the discussion mentioned above, an immediate need to depart from the current NOGA practice of using the unconstrained dispatch for the calculation of the settlement prices is not seen, if the differences remain in the same range as in our observations. Therefore, the simulations provided in this report for the modeling of the current Israeli market along with the different pricing approaches that are proposed are based on the unconstrained model only.

The practical recommendations for each type of constraint present in the constrained but not in the unconstrained computation are summarized in Table 1. However, should the deviations between constrained and unconstrained prices become significant in the future, one may need to reassess whether the political objectives of the approach are counter-productive. For example, this would be the case if the approach is intended to reduce the market clearing prices, but, in the short-term, the resulting increase in the NOGA tariffs are such that the total cost of consumers is increasing, while insufficient incentives are given in the longer term to reduce the issue.

Table 1: Table containing the recommendations to include or not a particular type of constraint in the unconstrained optimization program. The type of constraints listed are constraints that are currently involved in the constrained model but not in the unconstrained version of the Israeli electricity market.

Constraint Type Names	Descriptions	Recommendations
Transmission constraints	Constraints limiting the production of different assets due to limits on the transmission network.	This constraint does not seem to be currently excluded for “political reasons” since they represent limitations of the electricity network. *We therefore advise on adding such type of constraints to the unconstrained model, to improve consistency between operations and pricing.*
Gas system constraints	The amount of available natural gas over a day for the entire Israeli system is limited, thus restricting the possible amount of electric power that can be produced by natural gas units.	Based on our discussions with NOGA, this constraint seems to be kept only in the constrained model for “political reasons”. Indeed, the goal seems to avoid the price (and therefore consumers) to be affected by gas shortages. *We therefore advise on keeping this constraint only in the constrained program if unconstrained and constrained prices remain relatively close.*

Backup fuel usage	Some units have the possibility to run on two different fuels so that, when a shortage of natural gas occurs, these dual units can provide electric power using their backup fuel.	This constraint also exists for "political reasons" to limit the electricity prices in specific cases. It only makes sense to maintain this constraint in models which contain the previous constraint about system gas shortage. *We therefore advise on being consistent and adding this constraint only in the models which contain the previous constraint.*
Unit tests	Dual fuel units, that have the possibility to operate on two different fuels (their primary fuel is gas and their secondary fuel is gasoil), are required to perform a test once a month, by running on their dual fuel for a few hours. These tests are accounted for in the constrained model (as must-run time for the unit) while in the unconstrained model dual fuel units are considered to operate on gas only.	Based on our discussions with NOGA, we understand that this constraint was not added in the unconstrained model for "political reasons" as it allows the cost of unit tests not to be reflected on final consumers through market clearing prices. *We therefore advise on keeping this constraint only in the constrained program as long as unconstrained and constrained prices remain relatively close.*
Environmental constraints	Constraint limiting the production of some units due to environmental externalities such as restrictions on CO_2 emissions in a particular city.	Based on our discussions with NOGA, we understand that this constraint is not added in the unconstrained model for "political reasons" as it allows NOGA to avoid reflecting the cost of environmental measures on consumers. *We therefore advise to keep this constraint only in the constrained program, as long as the unconstrained and constrained prices remain relatively close.*

With respect to the constraints that are currently part of both the constrained and unconstrained programs (i.e., the constraints that are not listed in Table 1), we advise NOGA to maintain these operational constraints in both programs in order to, in the same spirit as the previous recommendations, obtain dispatches and prices that are as consistent as possible and so as to better reflect the current state of the Israeli power system. Among these constraints, we can cite, for example, constraints that are related to system operations, such as:

- Some units are forced to operate for a certain number of hours (24 or less);
- Some units are forced to be shut down, even though it would be less expensive to use them in practice;
- Some units are forced to operate at maximum to a lower level compared to their original maximum capacity;
- Some units are forced to operate at least at a higher level compared to their original minimum stable limit.

2.3 Non-convexities

Non-convexities refer to the cost structure and technical constraints of specific units which lead to market models that are “non-convex” in the sense that the corresponding mathematical optimization problems are “non-convex” (Figure 5).

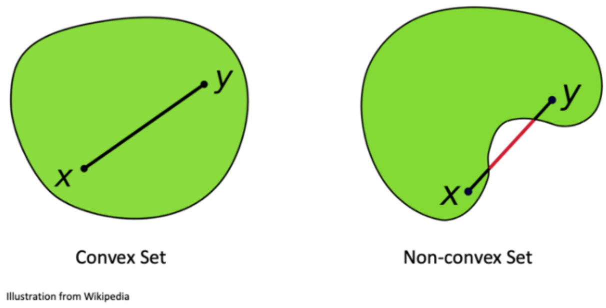


Figure 5: Convexity has a natural graphical interpretation. A set is convex if, for any two points that we pick in the set, the line that connects the two points lies within the set. In the opposite case, the set is non-convex. The set in the left part of the figure is convex, whereas the set in the right is non-convex.

An example of non-convexities is given by commitment costs such as minimum load costs and startup costs.

Marginal prices by definition do not reflect commitment costs (minimum load, start-up, etc) and may hence lead to high make-whole payments. These make-whole payments are typically required because minimum load costs and/or startup costs are not recovered via the payments which would depend on the MCP alone.

It is well known that, in the presence of non-convexities, truly optimal prices in the sense defined above, also called market equilibrium prices, do not exist in general [13]. Various approaches are used in international electricity markets in order to address this challenge. For example, MISO uses Extended Locational Marginal Pricing (also called Convex Hull Pricing) “*to effectively incorporate commitment costs into prices*”, and PJM uses “integer relaxation” to compute the day-ahead market prices [14].

2.3.1 Convex Hull Pricing: Rationale and Naming

Convex Hull Pricing aims at minimizing the impact of non-convexities in terms of lost opportunity costs (missed revenues) or losses (which are compensated via make-whole payments). These missed revenues or losses occur because a unit operates at higher costs than what the MCPs allow it to recover, or because a unit is asked to operate below a level that maximizes its profits. Computing Convex Hull Prices exactly can be computationally hard.

The graphical intuition of how (exact) convex hull prices are computed is given in Figure 6. The green curve in the figure corresponds to the cheapest way in which one can produce Q MW from the suppliers. The orange curve depicts the convex hull of this system cost function: this is the closest convex function sitting underneath the green curve. If the products were not “complicated” (i.e. if they were convex), we would arrive at the orange supply function. Convex hull prices are the prices you would get in this nice setting, which is the closest convex approximation (which is the mathematical definition of the convex hull) to the true setting.

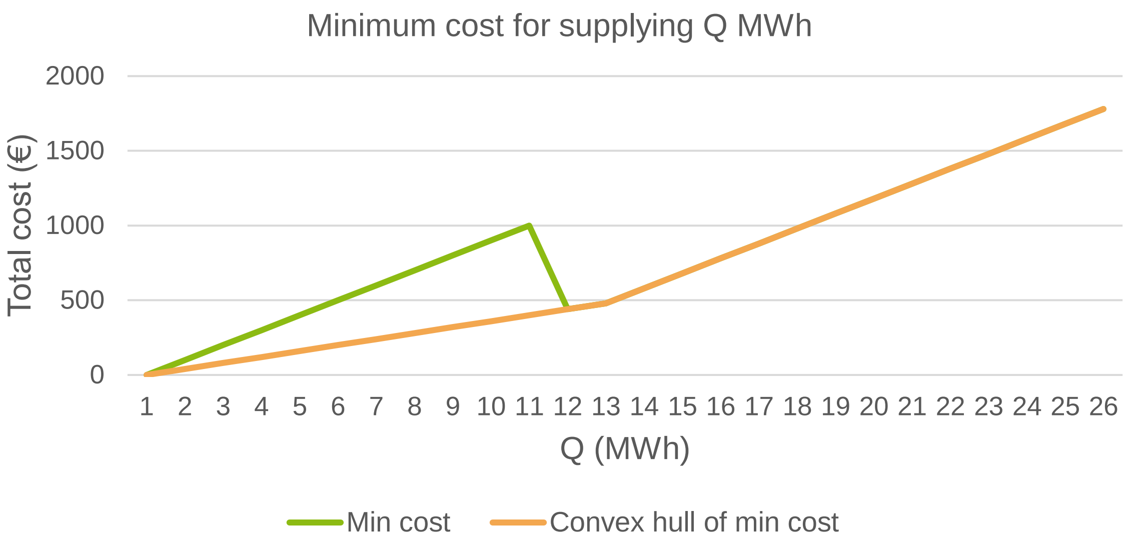


Figure 6: A graphical interpretation of how convex hull prices are computed

Some key advantages and disadvantages of Convex Hull Pricing are pointed out by the US ISO PJM [18]:

- Advantages: “Convex-hull pricing produces a more “intuitive” relationship between changes in load and price: When load increases, price either stays the same or increases. When load decreases, price either stays the same or decreases. In addition, convex-hull pricing incorporates start-up and no-load costs into the price, minimizes total uplift and allows block-loaded resources and those operating at their minimum or maximum limits to affect the price when appropriate."
- Disadvantages: “Convex-hull pricing is difficult to calculate computationally and is difficult to interpret. In addition, convex-hull pricing can have “counter-intuitive” properties, such as positive prices for non-binding system constraints (i.e., transmission or reserve constraints). Since implementing convex-hull pricing is not computationally feasible, an approximate convex-hull solution can be calculated using separate dispatch and pricing runs. Almost universally, ISOs/RTOs use separate dispatch and pricing runs in their approximate ELMP designs.”

2.3.2 Approximate convex hull pricing via the integer relaxation

One approach for computing approximate convex hull pricing is via the “integer relaxation”, which corresponds to the PJM practice today [14].

In certain specific technical contexts, this “integer relaxation” provides exact convex hull prices, and in other cases it leads to market prices that are close to the exact convex hull prices. The integer relaxation approach to convex hull pricing is exact when dropping the integer or binary requirements on the variables that are used to model the commitment decisions (starting up a unit, producing at least a minimum load level, etc) provides the so-called “convex hull” of the set that describes features of a unit (technical constraints and cost structure).

The intuition on the integer relaxation methodology, which we refer to hereafter as approximate convex hull pricing, is as follows: the same standard marginal pricing principles are used, but are applied to a pricing run where (a) binary commitment decisions are allowed to take fractional values (e.g., a minimum load level is enforced only at 60%), (b) costs associated to these commitment decisions are treated as “variable costs” depending on the percentage of acceptance of the decision, and are somehow “adders” to what is otherwise setting the MCP.

For example, virtually operating a unit at 40% of its minimum stable generation, say generating 40MW as 40% of the minimum stable limit of 100MW, will incur a cost of 40% of the minimum load cost. Suppose that this minimum load cost is 15000$ for producing 100MW and that the variable cost is 50$/MWh. The minimum load cost can be described in the optimization model as 5000$ of variable costs incurred to produce at the minimum level of 100MW at 50$/MWh, plus 10000$ of no-load costs. In the continuous relaxation where one can virtually operate below the minimum stable generation, only 40% of the 10000$ will be incurred, that is 4000$ for virtually producing 40MWh, which corresponds to an adder of 4000/40 = 100$/MWh that is added to the variable cost of 50$/MWh. In a simple one-hour period market setup where this unit would set the price, the price would be set at 100$/MWh + 50$/MWh = 150$/MWh. Another way to look at this same example is to consider the minimum load cost of 15000$ as the total cost of a generation of 100MWh at a “marginal cost” of 150$/MWh for an indivisible production. If the unit is committed at 40% in the integer relaxation and sets the price, the price will be set at 150$/MWh. In this alternative view, we don’t even distinguish between no load costs and generation costs. The discussion where the distinction is made above is useful to also interpret the impact of startup costs (closer to no load costs than to minimum load costs since by definition they are not tied to a generation level).

3 Simulation results of the price calculation options for 2021

Based on the analysis of the previous section, two alternative MCP calculations methods are considered for comparison.

- The first approach, namely “marginal pricing with fixes”, corresponds to low effort in terms of implementation and facilitates the interpretability of the different results. It is the one used by CAISO, the California Independent System Operator, at the time of finalizing this report.
- The second approach, approximate Convex Hull pricing, relies on a relaxation of the different binary variables. It is used in practice currently by the US Independent System Operator PJM [13]. As opposed to the first approach, it is more difficult to interpret the market clearing prices obtained via this method.

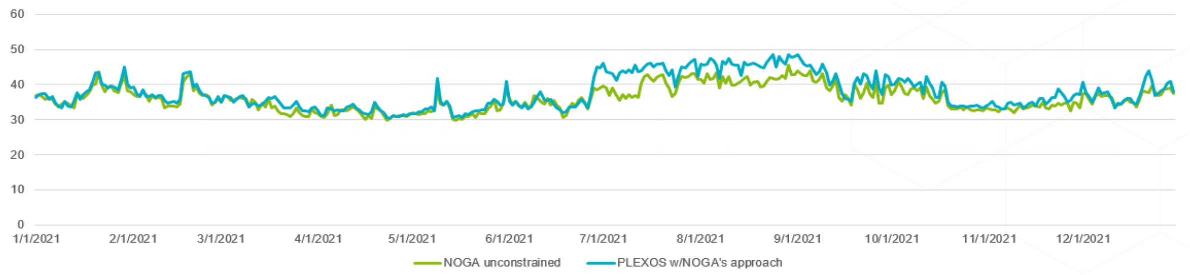
These two alternative approaches are compared in this section to the current practice used by NOGA to compute the MCP on historical data in 2021. Before performing this comparison, a model replicating the dispatch and pricing obtained by NOGA in 2021 was developed and verified.

3.1 Replication of the dispatch and pricing of NOGA in 2021

The objective of this analysis is to prepare the model for analyzing the proposed options to modify the market clearing price calculation and to ensure that this model is sufficiently accurate to replicate the historical results.

The model of the Israeli market was constructed in the commercial platform Plexos® based on the data and assumptions provided by and agreed with NOGA. Based on the Plexos® dispatch results, the MCP calculated based on NOGA’s approach was replicated using a bespoke XLS model.

The results of the MCP replication compared to the NOGA’s unconstrained MCP is presented in Figure 7 below.



Month	PLEXOS w/ NOGA's approach	NOGA Unconstrained	Difference (%)
January	37.95	37.35	2%
February	37.38	36.61	2%
March	34.69	33.74	3%
April	32.25	31.70	2%
May	33.53	32.66	3%
June	35.39	34.90	1%
July	44.26	39.66	12%
August	46.08	41.42	11%
September	41.79	39.17	7%
October	37.36	35.77	4%
November	35.19	33.55	5%
December	37.57	36.65	3%
		% Difference ->	5%

Figure 7: Results of the MCP replication compared to the NOGA's unconstrained MCP

Differences are observed between the MCP replication and NOGA's unconstrained MCP, mainly in the months of July and August. These differences are due to different dispatch results. Indeed, during these months, there are several half-hourly periods where partially loaded units (due to operational constraints that were not simulated in the replication) set the price. In the replication, some of these partially loaded units are now fully loaded. As a result, more expensive units were partially loaded and set the price.

3.2 Comparison of the alternative MCP calculations

We compare here the MCP obtained with (a) the current approach of NOGA, (b) Marginal Pricing with fixes, and (c) approximate Convex Hull Pricing. The comparison is shown in Figure 8, Figure 9, Figure 10, for specific days, and Table 2 provides an overview of the average MCP computed on a monthly basis.

The figures clearly show the following tendencies:

- First, Marginal Pricing with Fixes leads to a price signal that is strongly correlated with the current MCP calculated by NOGA, but which is consistently higher. This is mainly due to the "fixes" evoked for properly defining which units are "partly loaded" (e.g., properly taking into account ramp conditions), the interaction of pricing with the reserve requirements, and the effect on prices of intertemporal constraints originating from the operation of the hydro pumped storage units. Since the cheapest "seemingly partly loaded unit" may turn out not to be actually partly loaded, the true marginal cost of the system is usually substantially higher, which materializes in the figures below.

- Second, as expected, approximate convex hull prices are higher than marginal prices with fixes, because they reflect commitment costs (such as startup and minimum load costs) more accurately in the MCP. For example, the price spikes that can be observed on October 6th occur at periods where a couple of plants are starting up (or starting up at the preceding period). We can also observe that approximate convex hull prices are, on average, substantially higher during the peak season from July to September. The reason is that more units need to be committed during summer, leading to higher commitment costs (startup costs and minimum load costs), which are better reflected in the MCP with approximate convex hull price.

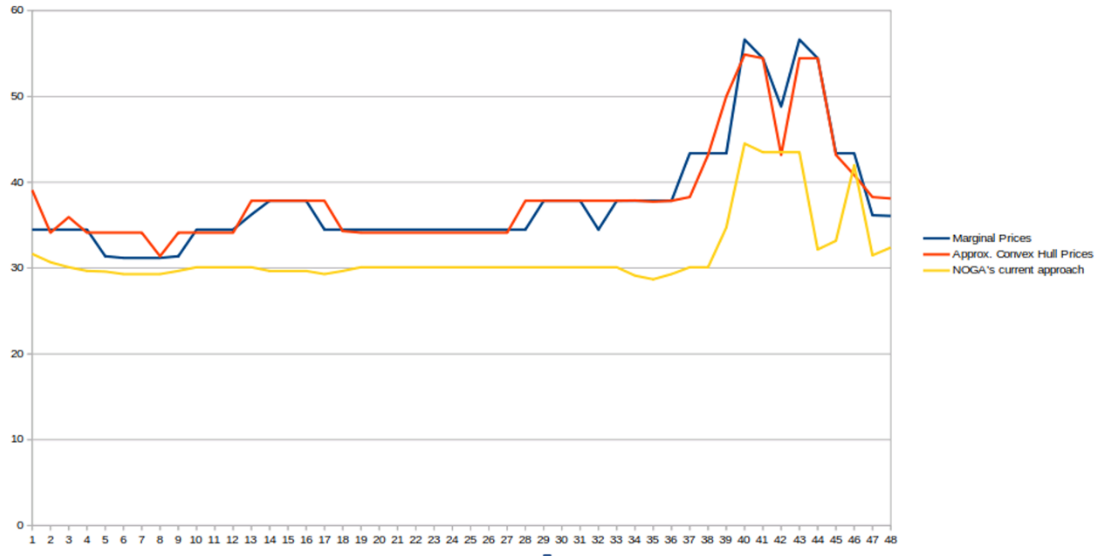


Figure 8: Prices on April 6th, 2021, for the different pricing methods

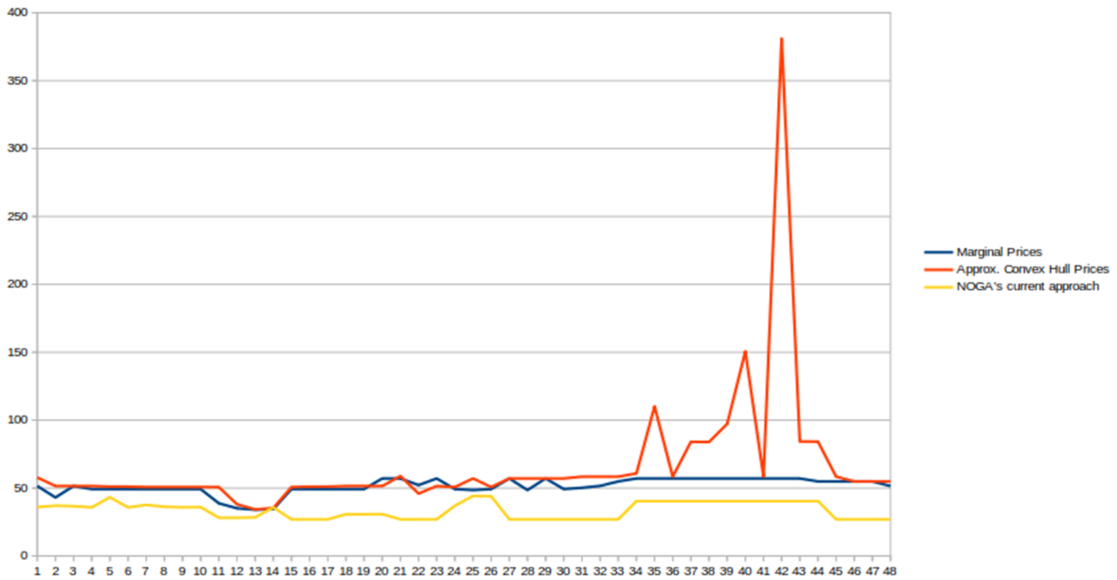


Figure 9: Prices on July 6th, 2021, for the different pricing methods

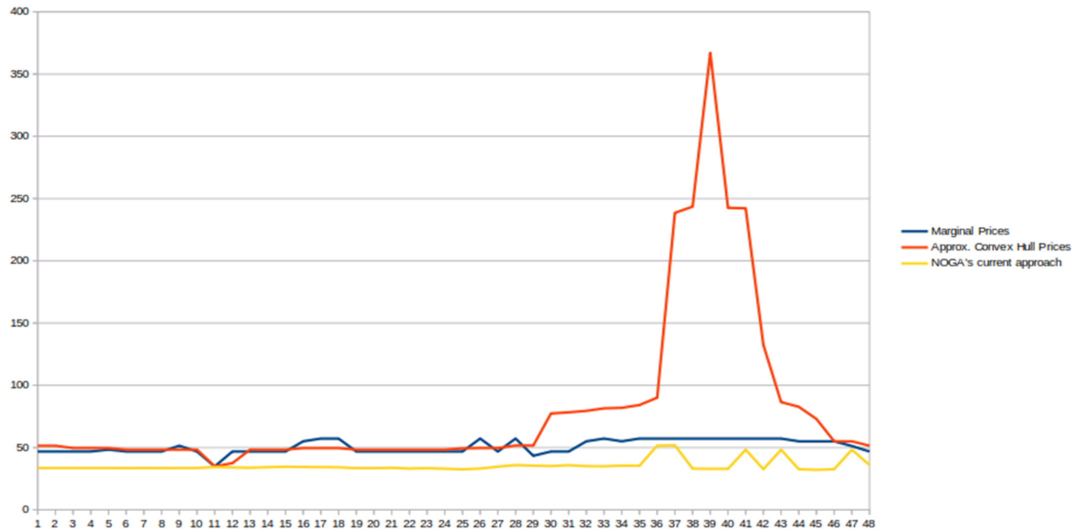


Figure 10: Prices on October 6th, 2021, for the different pricing methods

Table 2: Average, minimum and maximum monthly prices for the different pricing

	Average			Min			Max		
Month	**NOGA ($/MW)**	**Marginal Prices ($/MW)**	**Approx CH Prices ($/MW)**	**NOGA ($/MW)**	**Marginal Prices ($/MW)**	**Approx CH Prices ($/MW)**	**NOGA ($/MW)**	**Marginal Prices ($/MW)**	**Approx CH Prices ($/MW)**
January	37.62	47.09	46.91	29.39	0.00	0.00	323.48	215.00	385.04
February	37.02	40.50	43.34	29.48	0.00	0.00	60.52	215.00	358.54
March	33.89	37.57	38.56	28.14	0.00	1.54	60.59	67.25	354.10
April	31.79	37.34	37.42	27.18	0.00	0.00	54.45	67.26	228.93
May	32.85	42.64	45.89	25.98	0.00	15.70	50.41	509.09	558.17
June	35.10	43.90	51.25	28.79	30.65	30.65	51.38	122.23	389.00
July	39.92	53.65	83.61	26.97	31.35	31.57	54.09	131.96	405.97
August	42.71	61.14	97.32	30.20	34.05	34.25	291.70	595.22	609.05
September	39.20	48.16	66.46	29.90	32.80	31.02	55.49	464.71	416.02
October	35.51	43.76	53.10	29.36	28.06	21.36	54.83	534.12	497.23
November	33.65	38.33	43.78	28.38	27.99	15.55	57.25	149.60	393.82
December	36.67	39.80	55.78	29.86	0.00	0.00	319.59	141.49	441.35
Yearly Statistic	36.33	44.56	55.44	25.98	0.00	0.00	323.48	595.22	609.05

Approximate convex hull prices in the last column are in particular driven by startup and minimum load costs: if these costs are lower in the future, for example as the result of market monitoring processes, lower approximate convex hull prices are expected.

4 Summary of recommendations on MCP approach

Based on the analysis of the results presented in section 3 along with the discussion on gaps found in the current MCP computation method of NOGA presented in section 2, this section summarizes the recommended improvements with respect to the current price computation process in the Israeli electricity market. Table 3 provides a summary of the proposed recommendations along with an assessment of their potential impact in terms of price consistency and implementation efforts.

Table 3: Summary of the different proposed recommendations which aim at improving the current Israeli price computation process.

Elements of the approach for improving the pricing method	***Objective 1: Optimal prices consistent with the dispatch***	***Objective 2: Prices allowing to minimize the uplift***	***Objective 3: Implementation efforts***
Implement pricing using dual multipliers: Replace the current business rules of price calculation by setting the prices at the dual prices reflecting the exact marginal cost of energy.	Yes	No	Purchase of commercial optimization software
Approximate convex hull approach	Yes	Partially	Customized model that can be solved by commercial software
Apply convex hull approach: Compute exact convex hull prices using more advanced methods	Yes	Yes	Requires customized solution, significantly more complex than previous solution

From the summary of these recommendations, two detailed market clearing price calculation methods are deemed relevant for the Israeli context: ***Marginal Pricing with fixes*** and ***Approximate Convex Hull Pricing***.

These two methods are designed according to recommendations and tested on 2021 data. These simulations show that:

- Both standard marginal pricing and (approximate) convex hull pricing led to MCPs being close to each other on many simulation days. However, they differ by a large amount in some periods of specific days. For that reason, the

N-SIDE COMPASS LEXECON NOGA Israel Independent System Operator

average approximate convex hull prices turn out to be substantially higher than the average marginal prices, leading to lower make-whole payments but higher total settlements as the end effect. Lower start-up costs and/or minimum load costs would reduce the difference between the two pricing approaches.

- Standard marginal pricing, compared to (Approximate) Convex Hull Pricing, is easier to interpret since there is no need to understand how costs associated to the binary commitment decisions (startup costs, etc), which are allowed to be fractionally accepted in the pricing run, add to the marginal system costs to form the MCP.

Based on these observations, **the marginal pricing approach** is selected as the main alternative to the current MCP approach and applied in the forward analysis of the Israeli electricity system presented in the following section.

5 Forward analysis for 2024-2026

In this section we present the details of the forward analysis of the Israeli electricity system using different prospective scenarios for the period 2024-2026. The objective of this analysis is to inform about the future evolution of MCP if the recommended pricing option put forward in this study is applied.

For that purpose, we have developed a Base Case scenario of 2024, 2025 and 2026 and compared the prices obtained both via NOGA's current approach to calculate the MCP and the proposed MCP approach.

5.1 Forward model setup and key updates

The forward-looking analysis is built upon the model initially developed for year 2021 described above updated using the latest data and assumptions provided (known information due to 2023) and validated by NOGA. In particular, the analysis accounts for the demand projections of the Israel power system, projected evolution of the Israeli power fleet and its characteristics, an update on units ownership and regulation and application of various system constraints (Appendix C).

5.2 Base Case Scenario Results

Table 4 and Table 5, respectively, show yearly statistics of the prices obtained with the current NOGA's pricing approach and the ones obtained with the marginal pricing approach.

Table 4: Prices computed using NOGA's current pricing approach.

Year	Mean	Min	Median	Max
2024	29.8	26.0	29.9	48.8
2025	29.7	26.0	30.0	44.6
2026	29.8	26.0	30.0	49.9

Table 5: Prices computed using marginal pricing approach.

Year	Mean	Min	Median	Max
2024	38.8	0.1[3]	37.2	500.8
2025	42.0	0.1	37.2	588.5
2026	41.7	0.1	37.2	577.1

A comparison of the prices reveals that the average prices obtained using marginal pricing are higher than those obtained using NOGA's current method. This spread can be explained by the fact that marginal pricing allows to better reflect and account for the scarcity that the system would experience due to the phase out of coal.

It can also be observed that this difference increases between 2024 and 2025, as shown in Figure 11. This increment is again linked with the coal phase out which leads

[3] 0.1 – Price of curtailed renewables

to a rise in expensive gasoil units' usage. Note that this factor also explains the difference in maximum values between both pricing approaches.

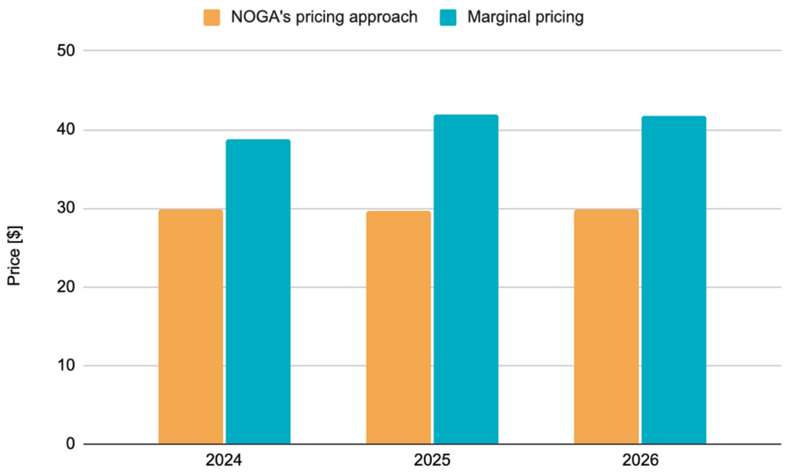


Figure 11: Comparison of annual average prices using NOGA's current pricing approach and marginal pricing.

Moreover, an analysis per month of the two pricing approaches, provided in Table 6 for the period 2024-2026, shows that the main differences occur in high demand periods (January and summer months), when, due to the limit on the daily gas consumption, more expensive gasoil units are needed to cover the demand.

Table 6: Comparison of monthly average, minimum and maximum prices using NOGA's current pricing approach and marginal pricing in 2024, 2025 and 2026.

2024 Months	Marginal Pricing			NOGA's Pricing Approach		
	Average Price ($\MWh)	Maximum Price ($\MWh)	Minimum Price ($\MWh)	Average Price ($\MWh)	Maximum Price ($\MWh)	Minimum Price ($\MWh)
1	51.6	500.8	0.1	29.0	41.4	26.0
2	32.6	49.9	0.1	28.7	33.0	26.0
3	29.8	49.9	0.1	28.1	33.0	26.0
4	28.7	49.9	0.1	28.4	33.0	26.0
5	33.2	390.2	0.1	28.1	31.4	26.0
6	37.3	49.9	0.1	28.6	31.4	26.0
7	44.5	500.8	26.0	31.6	48.5	26.0
8	50.4	500.3	29.5	31.5	45.6	26.0
9	42.0	61.5	26.0	31.4	45.9	26.0
10	38.0	485.4	0.1	30.7	45.0	26.0
11	38.9	50.0	0.1	31.5	48.8	26.0
12	37.6	50.0	0.1	30.3	48.0	26.0

2025 Months	Marginal Pricing			NOGA's Pricing Approach		
	Average Price ($\MWh)	Maximum Price ($\MWh)	Minimum Price ($\MWh)	Average Price ($\MWh)	Maximum Price ($\MWh)	Minimum Price ($\MWh)
1	57.8	588.5	0.1	30.0	41.7	26.0
2	36.3	74.7	0.1	29.3	37.2	26.0
3	32.6	49.9	0.1	28.7	44.4	26.0
4	27.0	49.9	0.1	28.2	33.0	26.0
5	40.3	500.8	0.1	29.8	44.6	26.0
6	38.7	485.4	0.1	30.1	33.7	26.0
7	58.9	500.8	27.7	30.5	37.2	26.0
8	69.3	558.3	26.0	30.2	37.2	26.0
9	45.1	500.8	0.1	30.8	41.7	26.0
10	33.8	49.9	0.1	30.1	40.4	26.0
11	30.1	48.0	0.1	29.6	32.0	26.0
12	32.9	51.0	0.1	29.6	37.2	26.0

2026 Months	Marginal Pricing			NOGA's Pricing Approach		
	Average Price ($\MWh)	Maximum Price ($\MWh)	Minimum Price ($\MWh)	Average Price ($\MWh)	Maximum Price ($\MWh)	Minimum Price ($\MWh)
1	67.5	577.1	0.1	30.2	45.0	26.0
2	40.0	488.3	0.1	29.3	48.0	26.0
3	27.6	48.0	0.1	28.3	33.0	26.0
4	19.1	45.0	0.1	27.4	36.5	26.0
5	32.4	209.6	0.1	29.4	40.8	26.0
6	34.1	48.0	0.1	29.7	33.0	26.0
7	52.8	500.8	26.0	31.5	40.8	26.0
8	88.3	577.1	28.0	31.9	45.6	29.4
9	47.9	518.0	0.1	31.2	49.9	26.0
10	32.1	48.0	0.1	29.9	37.0	26.0
11	27.0	48.0	0.1	29.2	33.0	26.0
12	29.8	48.0	0.1	29.4	37.2	26.0

The monthly distributions of hourly prices obtained using the marginal pricing approach are presented in Figure 12, Figure 13 and Figure 14 respectively for years 2024 to 2026. Furthermore, minimum and maximum prices are presented for each month of year 2024-2026 during off-peak and peak hours respectively in Figure 15, Figure 16 and Figure 17 for the same pricing approach[4]. All the aforementioned results confirm the observation that prices tend to be higher during summer months and January when the system is scarce (large presence of high outliers and high maximum price observation).

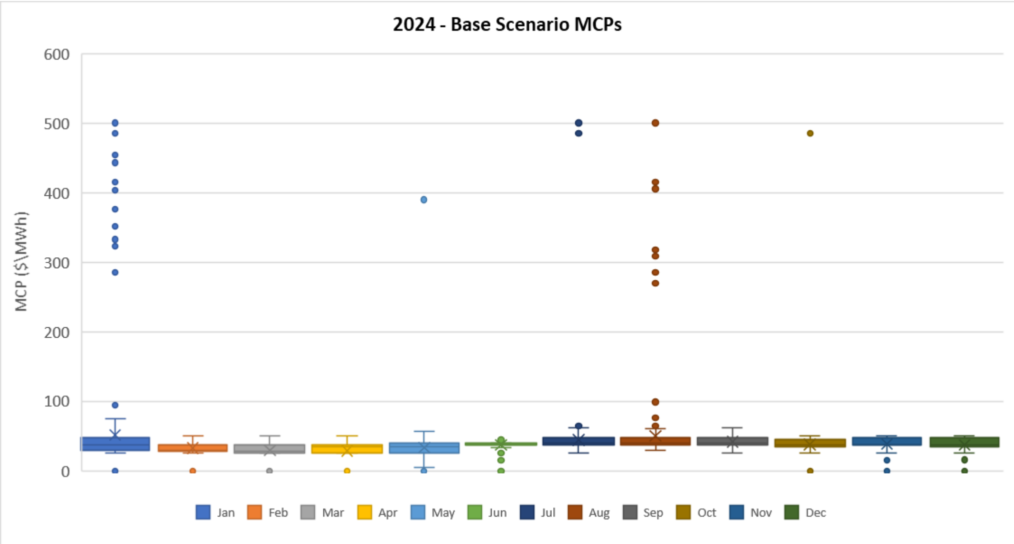


Figure 12: Monthly boxplots of the obtained prices for the Base Case in year 2024 computed with marginal pricing

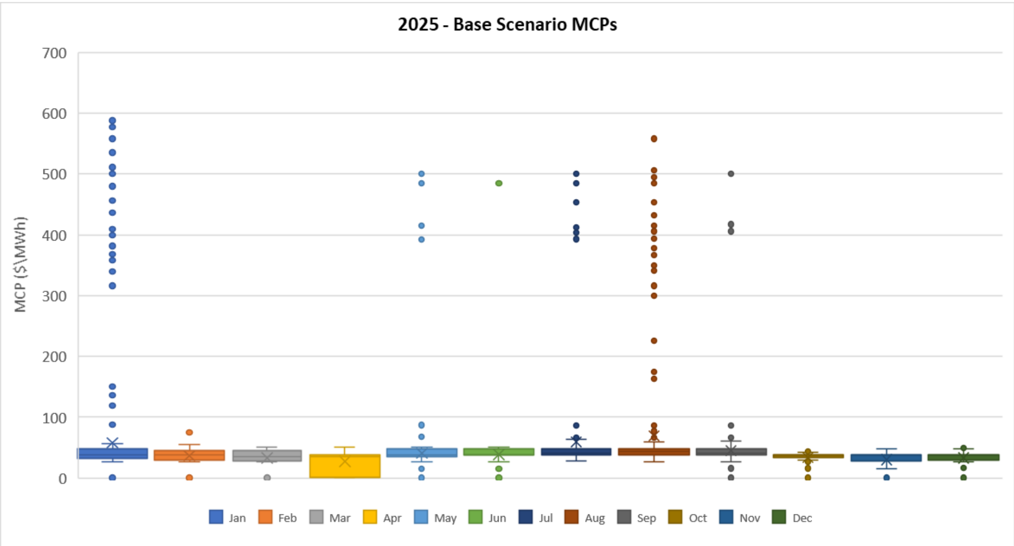


Figure 13: Monthly boxplots of the obtained prices for the Base Case in year 2025 computed with marginal pricing

[4] The Peak hours and Off Peak hours are defined according to Public utility authority policy 63609 ("MASHAV")

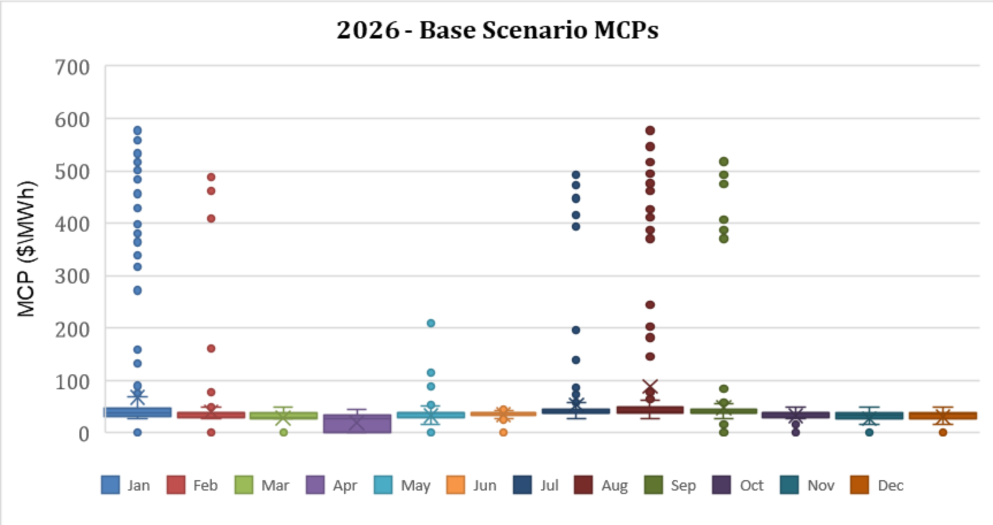


Figure 14: Monthly boxplots of the obtained prices for the Base Case in year 2026 computed with marginal pricing

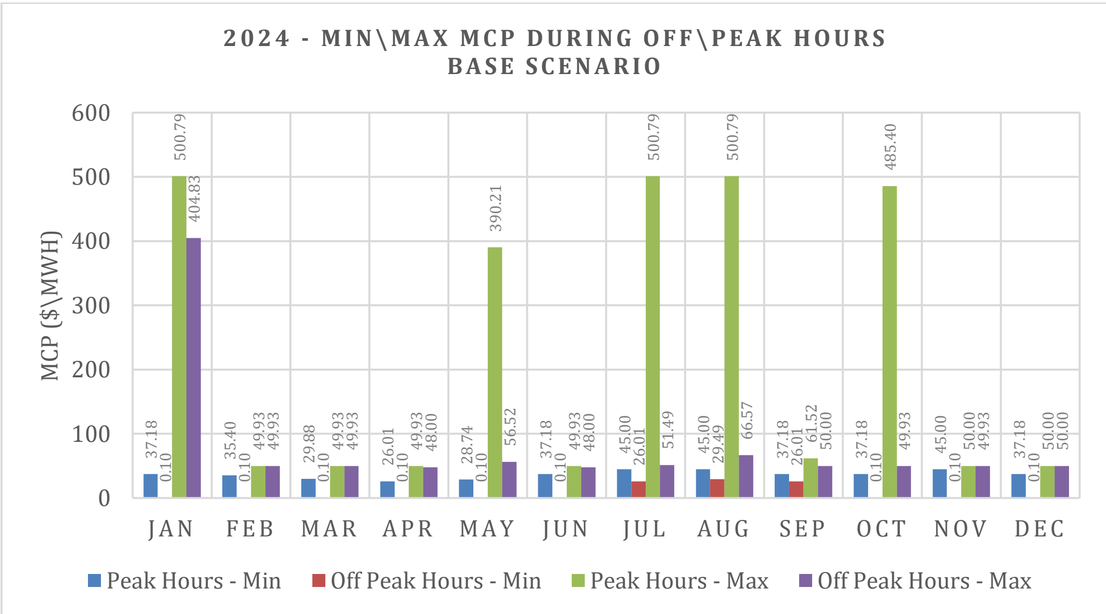


Figure 15: Monthly minimum and maximum observed prices for both peak and off-peak for the Base Case in year 2024 computed with marginal pricing

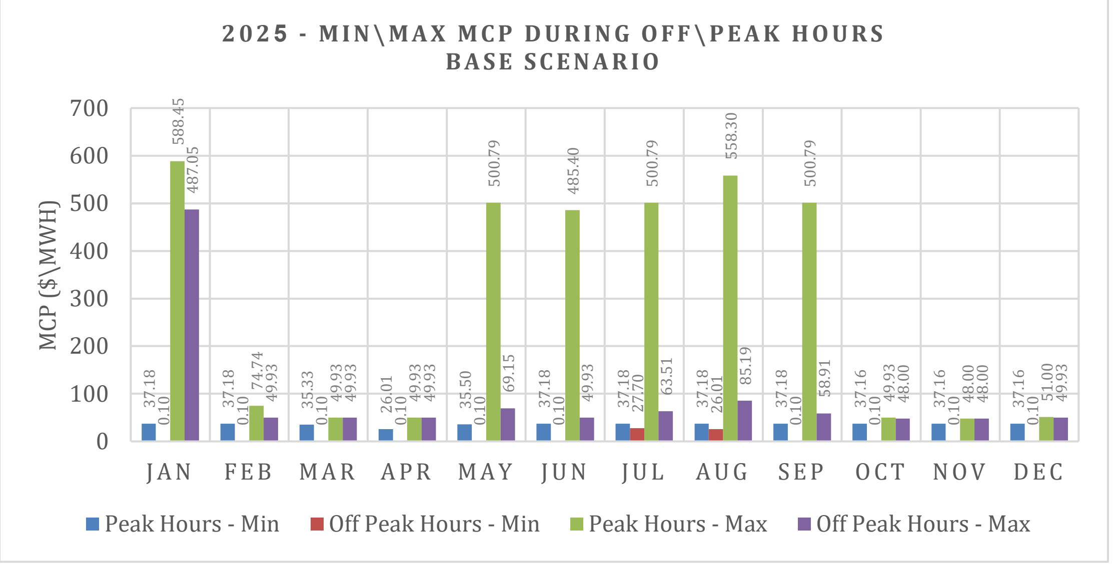


Figure 16: Monthly minimum and maximum observed prices for both peak and off-peak for the Base Case in year 2025 computed with marginal pricing

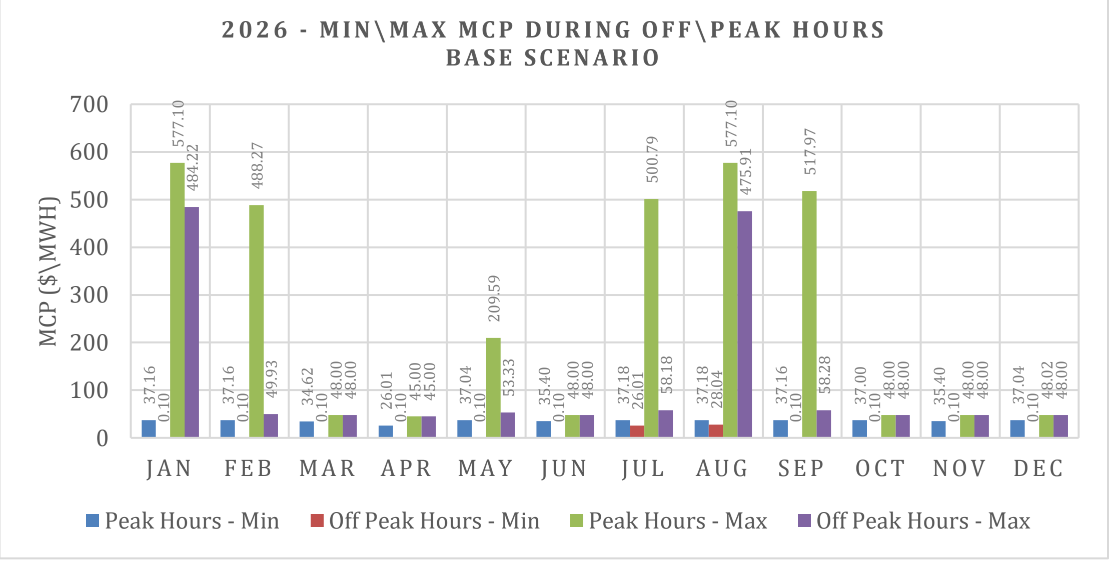


Figure 17: Monthly minimum and maximum observed prices for both peak and off-peak for the Base Case in year 2026 computed with marginal pricing

We also compared the make-whole payments and the total procurement costs simulated using the marginal pricing approach against those obtained with NOGA's current pricing approach whose results are presented in Table 7, Table 8 and Table 9.

Table 7: Yearly make-whole payments, procurement cost due solely to pay-as-clear units and total procurement cost for the marginal pricing approach as percentage of the yearly total procurement cost.

Year	Make Whole Payments (%)	Procurement Cost Pay-as-clear Units (%)	Total Procurement Cost (%)
2024	4%	17%	100%
2025	4%	19%	100%
2026	3%	15%	100%

Table 8: Yearly make-whole payments, procurement cost due solely to pay-as-clear units and total procurement cost for the current pricing approach used by NOGA as percentage of the yearly total procurement cost.

Year	Make Whole Payments (%)	Procurement Cost Pay-as-clear Units (%)	Total Procurement Cost (%)
2024	7%	15%	100%
2025	7%	14%	100%
2026	5%	10%	100%

Table 9 Yearly make-whole payments, procurement cost due solely to pay-as-clear units and total procurement cost expressed as a percentage of the marginal pricing approach with respect to NOGA's current approach.

Year	Make Whole Payments (%)	Procurement Cost Pay-as-clear Units (%)	Total Procurement Cost (%)
2024	61%	117%	102%
2025	55%	141%	106%
2026	63%	163%	106%

In conclusion, obtained results show that marginal pricing increases prices with respect to NOGA's current approach, thanks to a better representation of system scarcity. As a side effect, this phenomenon decreases make-whole payments with respect to the current pricing approach used by NOGA. Indeed, since pay-as-clear units are directly recovering a larger share of their incurred costs through market clearing prices, the remaining portion of their incurred costs that needs to be compensated is diminished. At the same time, the results suggest only a slight increase in the total procurement costs in the marginal pricing approach as compared to the current NOGA's approach.

5.3 Gas Shortage Scenario Results

In accordance with the data provided by NOGA, a special scenario representing a case where a stricter limit on the daily gas consumption is applied to the system was constructed. In this scenario, the daily gas consumption limit was reduced to 1,400,000 MMBTU as compared to 1,800,000 MMBTU of the base case. All other inputs were kept the same as the base case (resources information, demand, etc.).

Table 7 and Table 8, respectively, show yearly statistics of the prices for this gas shortage scenario obtained with NOGA's current pricing approach and the ones obtained with the marginal pricing approach.

Table 7: Prices computed using NOGA's current pricing approach.

Year	Mean	Min	Median	Max
2024	29.7	26.0	29.8	48.8
2025	29.7	26.0	30.0	45.9
2026	29.3	26.0	29.8	45.0

Table 8: Prices computed using marginal pricing approach.

Year	Mean	Min	Median	Max
2024	50.1	0.1	37.2	558.3
2025	85.5	0.1	37.2	588.5
2026	120.6	0.1	37.2	577.1

Similarly, to the results of the base case, prices of the gas constraint scenario obtained using marginal pricing are higher than those obtained using NOGA's current method. Main differences occur in high demand periods, when due to gas constraints, gasoil units are needed to cover the demand. Figure 18, Figure 19 and Figure 20 show detailed boxplots of the obtained prices in this scenario using marginal pricing respectively for years 2024-2026. Maximum and minimum prices during off-peak and peak hours are presented in Figure 21, Figure 22 and Figure 23 respectively. From these results, it can be observed that the prices in the gas constraint scenario are higher than in the base case during summer months and January. This phenomenon is explained by the tighter limit on daily gas consumption which is enforced in this scenario requiring a higher utilization of gasoil units than for the base case. Indeed, period of scarcity tends to be more frequent in this scenario due to the gas limit being stricter.

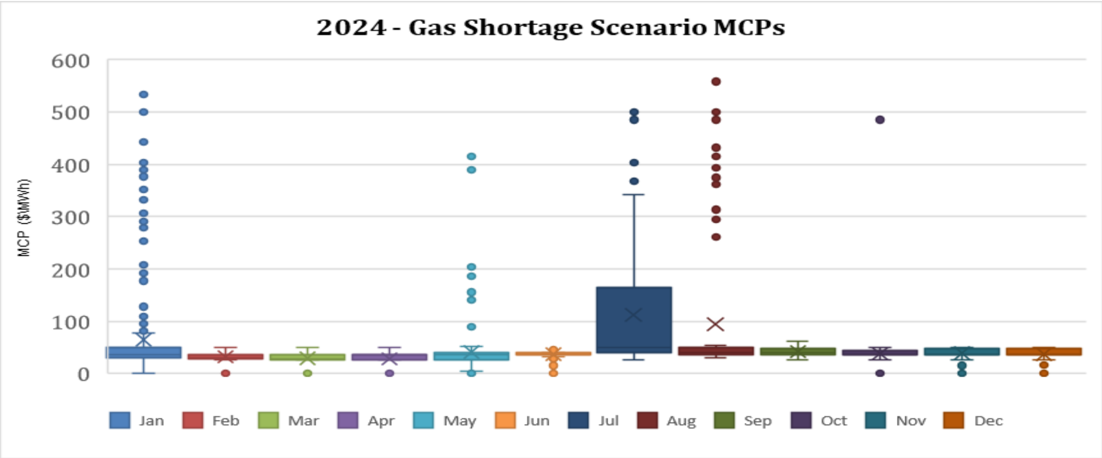


Figure 18: Monthly boxplots of the obtained prices for the Gas Shortage Scenario in year 2024 computed with marginal pricing

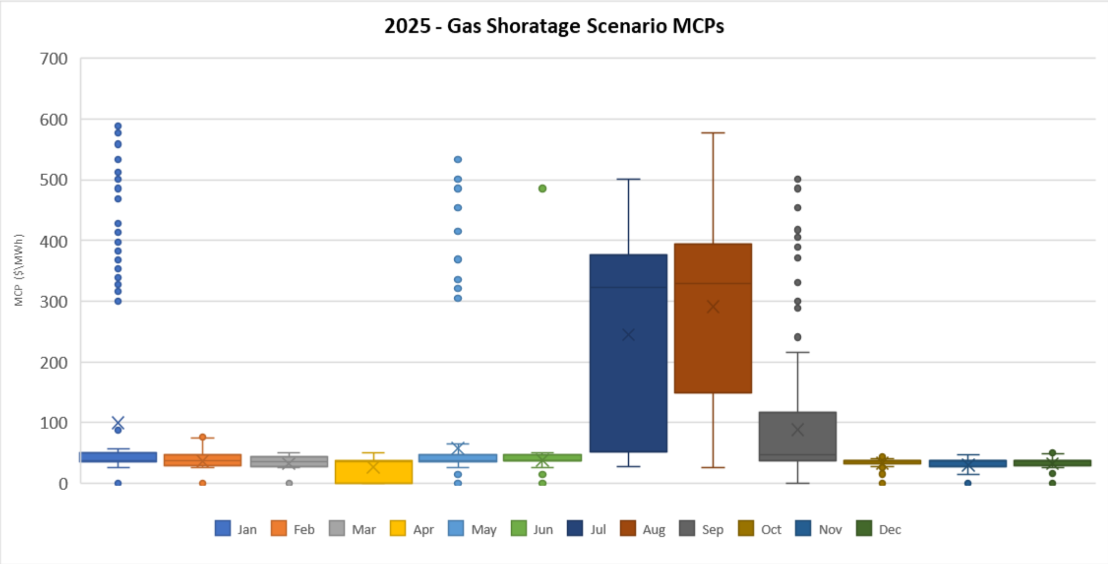


Figure 19: Monthly boxplots of the obtained prices for the Gas Shortage Scenario in year 2025 computed with marginal pricing

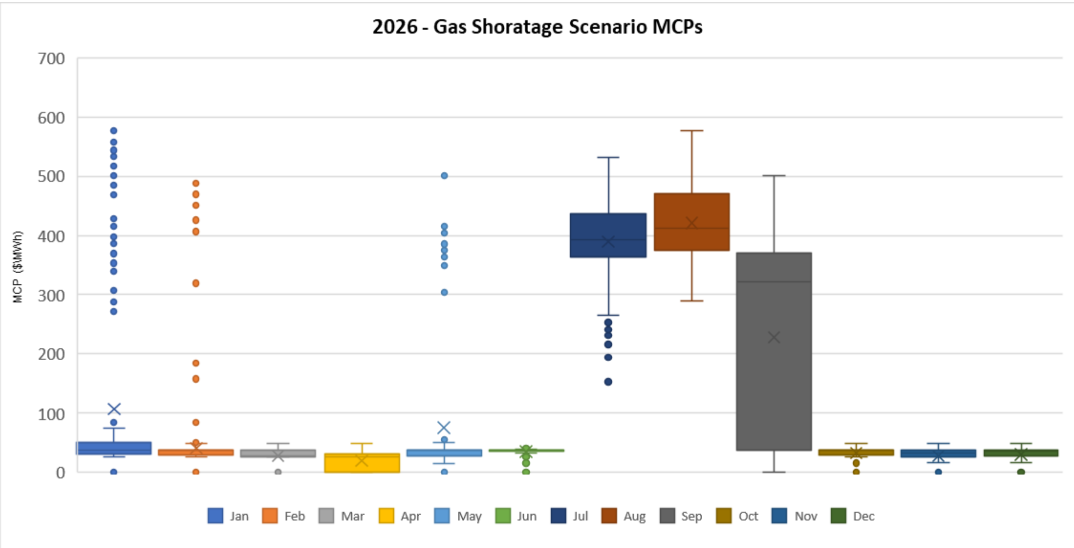


Figure 20: Monthly boxplots of the obtained prices for the Gas Shortage Scenario in year 2026 computed with marginal pricing

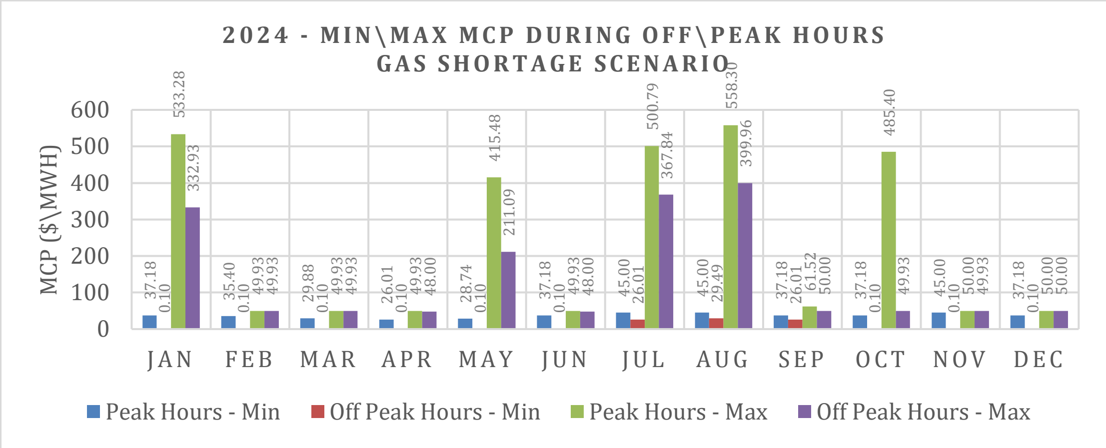


Figure 21: Monthly minimum and maximum observed prices for both peak and off-peak for the Gas Shortage Scenario in year 2024 computed with marginal pricing

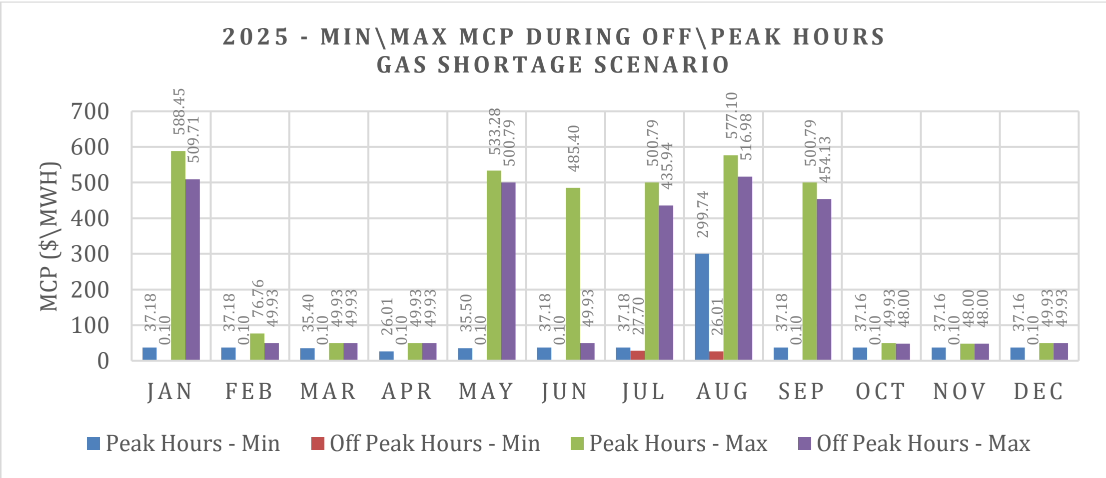


Figure 22: Monthly minimum and maximum observed prices for both peak and off-peak for Gas Shortage Scenario in year 2025 computed with marginal pricing

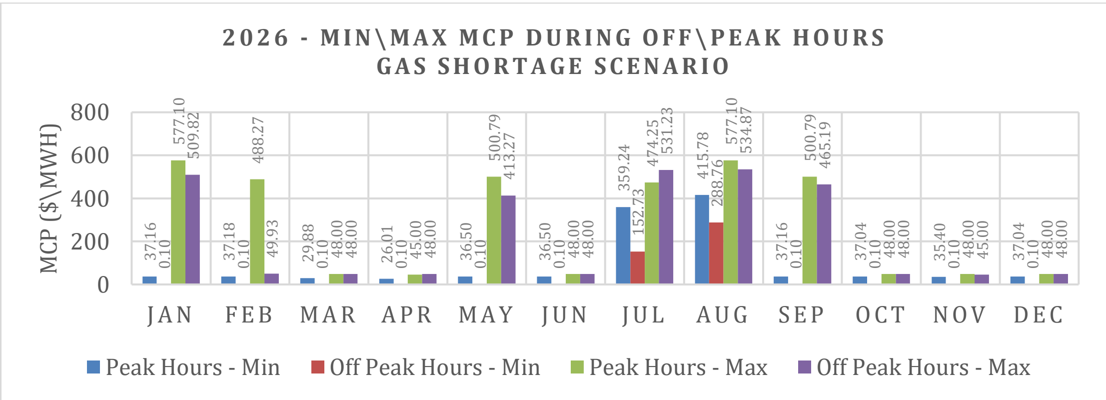


Figure 23: Monthly minimum and maximum observed prices for both peak and off-peak for the Gas Shortage Scenario in year 2026 computed with marginal pricing

We also compared the make-whole payments and the total procurement costs simulated using the marginal pricing approach against those obtained with NOGA's current pricing approach. The results of these simulations are provided in Table 10, Table 11 and Table 12.

Table 10: Yearly make-whole payments, procurement cost due solely to pay-as-clear units and total procurement cost for the marginal pricing approach as percentage of the yearly total procurement cost.

Year	Make Whole Payments (%)	Procurement Cost Pay-as-clear Units (%)	Total Procurement Cost (%)
2024	4%	23%	100%
2025	3%	37%	100%
2026	2%	38%	100%

Table 11: Yearly make-whole payments, procurement cost due solely to pay-as-clear units and total procurement cost for the current pricing approach used by NOGA as percentage of the yearly total procurement cost.

Year	Make Whole Payments (%)	Procurement Cost Pay-as-clear Units (%)	Total Procurement Cost (%)
2024	7%	15%	100%
2025	8%	15%	100%
2026	6%	11%	100%

Table 12 Yearly make-whole payments, procurement cost due solely to pay-as-clear units and total procurement cost expressed as a percentage of the marginal pricing approach with respect to NOGA's current approach.

Year	Make Whole Payments (%)	Procurement Cost Pay-as-clear Units (%)	Total Procurement Cost (%)
2024	56%	171%	111%
2025	46%	334%	135%
2026	44%	468%	142%

Note that the larger increase in proportion of the procurement cost due to pay-as-clear units and the total procurement cost in this scenario compared to the base case is related to larger observed prices during January and summer months than in the base case scenario due to a stricter daily gas consumption limit.

6 Preventing MCP manipulations by monitoring

Generally speaking, pay-as-clear auctions incentivize competitive **market players to truthfully bid their variable costs**. Economic theory states that **this leads to optimal short and long-term price signals and ultimately to minimum system costs**. This design mechanism is widely recognized as an **effective way to create a competitive and efficient electricity market.**

However, the benefits of the pay-as-clear auction design assume a competitive market, whereas the actual markets may feature market power issues. Market power refers to the ability of a single player or a group of players to influence market prices and outcomes to their advantage. This can lead to a distorted market and result in higher prices for consumers due to reduced competition.

To address market power issues, a range of market power mitigation measures can be considered. **The US and Europe have adopted different approaches** to monitor wholesale power markets to ensure that operators do not manipulate market outcomes or exercise market power:

- In the US, bids submitted by market participants into the DAM and RTM are subject to the ex-ante analyses of potential abuse of market power. Different tests are applied during the clearing process of the day-ahead and real-time markets to determine if there might be a risk of market power exercise in a specific segment of the transmission network.
- In Europe, market power mitigation is mainly conducted through ex-post investigations by NRAs under the competition policy or REMIT regulations, upon receiving specific signals or complaints. This leaves room for generators to bid above their short-term marginal cost (e.g. to include opportunity costs and to earn scarcity rent), unlike the US more systematic ex-ante market power screenings.

Regardless of the market power mitigation approach, market monitoring is considered an essential element of the market power mitigation. Market monitoring is necessary for building reliable spot markets and ensuring that market participants act in a fair and transparent manner. It helps to ensure that market participants do not engage in anti-competitive behavior, such as capacity hoarding or the manipulation of pivotal assets.

Market monitoring relies on two main paradigms:

- "Produce or Explain" and
- "Explain the Bid Prices."

The "**Produce or Explain**" paradigm requires market participants to be **able to justify why some assets have not been committed**. This helps to address abuses from capacity hoarding, where market participants may artificially limit supply to drive up prices.

The "**Explain the Bid Prices**" paradigm requires market participants to provide a **transparent explanation of the prices they have submitted**, **to ensure that they are not manipulating prices for their own benefit**. This latter approach has the reputation of being much easier to implement under a paid-as-cleared settlement regime, given the underlying incentives to bid at true marginal costs.

Market monitoring includes various techniques such as data analysis, market surveillance, compliance monitoring, and market transparency. Market monitors can use a combination of these techniques to effectively detect and address market power issues. Market monitoring is typically organized through a combination of the market operator and regulatory authority tasks, established under clear regulations and clear guidelines for market participants to follow. Market monitors can also have the authority to take enforcement actions, such as fines or penalties, against market participants that engage in anti-competitive behavior.

While caps on bid prices may be contemplated as a complementary measure to mitigate market power, they will in no way replace the need for a stringent market monitoring effort. If bid price restrictions are applied, they should be set with great care and be flexible enough to allow for unforeseeable market situations, such as unexpected supply disruptions. For example, during the EU gas crisis in 2022, prices rose significantly, which would have made it difficult to set meaningful restrictions on bid prices.

7 Conclusion

The analysis of the MCP calculation method of NOGA conducted in this project has identified several substantial issues which can be summarized as follows:

- Marginal Pricing defines the MCP in a given period based on the marginal system cost increase that would result from a marginal increase of the load in that period.
- The existing approach of NOGA, which defines the MCP based on the cheapest seemingly partly loaded unit (overlooking that resources to meet the reserve requirements may be limited, but also potentially neglecting the impact of ramp conditions limiting the available power in a given time period), attempts to apply this standard marginal pricing principle, but in a way, which is correct only in the simplest setups, e.g., in the absence of ramp conditions, hydro pumped storage or ancillary services requirements. The existing approach that was introduced by the regulator, as part of market reform in Israel in June 2018, has accompanied the switch to the new pay-as-clear electricity market for a restricted number of market participants settled at the Market Clearing Price. However, the pricing approach and its shortcomings reflect the fact that the market design is not mature enough at this stage.
- These shortcomings have been analyzed in detail. This leads to our proposal to compute MCPs based on standard marginal pricing principles, relying on so-called shadow prices (or optimal dual variables/Lagrangian multipliers) of the system balance conditions.
- The challenge of pricing non-convexities has also been examined in detail. While (approximate) Convex Hull Pricing better reflects commitment costs (which is the source of non-convexities) into the MCP, and is a relevant approach used in real-world markets (e.g., used by the Midcontinent ISO in the US) with solid theoretical foundations, market power mitigation measures may be a prerequisite for its possible implementation in the future, for example to mitigate the impact of market participants that would bid very high commitment costs.

Simulations of the alternative MCP approaches based on historical data of 2021 have shown that Marginal Pricing with fixes reduces make-whole payments by increasing the MCP compared to the existing approach of NOGA. On the other hand, due to high commitments costs reflected in the MCPs, Approximate Convex Hull Pricing leads to lower make-whole payments but significantly higher total settlements. Simulations were also performed on the forward period of 2024-2026 to compare the proposed marginal pricing and the current NOGA's pricing approaches. The results of these simulations suggest that the main differences in prices occur in high demand periods (January and summer months), when, due to the limit on the daily gas consumption, more expensive gasoil units are needed to cover the demand.

As a general conclusion, Marginal Pricing with Fixes is recommended, in view of its low implementation efforts, the easier interpretability of the pricing results and the best trade-off between low make-whole payments (high MCPs) and low settlements (low MCPs).

It should be emphasized that **Market Power Mitigation measures** in all cases are **strongly recommended to prevent market abuse based on make-whole payments**.

8 References

[1] E. Efremoushkin, A. Factorovich and I. Aronovich, "Technical Specification for Israeli Market Clearing Price Analysis," May 2021.

[2] A. Papavasiliou, ”Optimization models in electricity markets”, Cambridge University Press

[3] Madani, Mehdi, et al. "Convex hull, ip and european electricity pricing in a european power exchanges setting with efficient computation of convex hull prices." arXiv preprint arXiv:1804.00048 (2018).

[4] CAISO, “Bid cost recovery enhancements: straw proposal”, June 3, 2016

[5] Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing

[6] Balas, Egon. "Disjunctive programming: Properties of the convex hull of feasible points." Discrete Applied Mathematics 89.1-3 (1998): 3-44.

[7] FERC, 2013. Make-Whole Payments and Related Bidding Strategies, Docket Nos. IN11-8-000, IN13-5-000, Washington DC: Federal Energy Regulatory Commission.

[8] I. Aravena, Q. Lete, A. Papavasiliou, Y. Smeers, Transmission Capacity Allocation in Zonal Electricity Markets, Operations Research, vol. 69, no. 4, July-August 2021. Runner-up ENRE 2021 Best Publication Award in Energy

Available online: https://ap-rg.eu/wp-content/uploads/2021/11/J25.pdf

[9] I. Aravena, A. Papavasiliou, Renewable Energy Integration in Zonal Markets, IEEE Transactions on Power Systems, vol. 32, no. 2, pp. 1334-1349, March 2017

Available online: https://ap-rg.eu/wp-content/uploads/2020/07/J10.pdf

[10] Oren, Shmuel (2005), Market design and gaming in competitive electricity markets, UC Berkeley.

[11] Papavasiliou, A. (2021), ‘Investigation of the possibility of implementing a scarcity pricing mechanism in the context of the operation of the greek electricity market under the target model’, UC Louvain.

[12] Q. Lété, Y. Smeers, A. Papavasiliou, An Analysis of Zonal Electricity Pricing from a Long-Term Perspective, forthcoming in Energy Economics

Available online: https://ap-rg.eu/wp-content/uploads/2022/01/J36.pdf

[13] Stoft, Steven. Power system economics: designing markets for electricity. Vol. 468. Piscataway: IEEE press, 2002.

[14] PJM Interconnection, ” Proposed Enhancements to Energy Price Formation”, November 15, 2017.

[15] A. Papavasiliou, J. Cartuyvels, G. Bertrand, A. Marien, Implementation of scarcity pricing without co-optimization in European energy-only balancing markets, forthcoming in Utilities Policy

[16] A. Papavasiliou, Y. Smeers, G. de Maere, Electronic Supplement, Appendix to "Market Design Considerations for Scarcity Pricing: A Stochastic Equilibrium Framework"

[17] CREG, 2021. Study on the implementation of a scarcity pricing mechanism in Belgium, Brussels: Commission for Electricity and Gas Regulation.

[18] PJM, Important Concepts from Price Formation Education Session 2: Alternative Pricing Frameworks, 2018. Available online: https://www.pjm.com/-/media/committees-groups/stakeholder-meetings/price-formation/20180117-pm/20180117-price-formation-session-2-handout.ashx

Appendix

Appendix A - Detailed Answers to the Specific Questions

The objectives of the analysis provided in this report are detailed using a set of specific questions. The original questions are provided in ***bold and italic*** and are answered below in regular font. Note that each answer summarizes the content furnished in other sections of this report on a specific point.

1. ***Present the recalculated MCP prices under the MCP model and present the correlation between system demand and MCP prices. Comparison between original MCP prices and new model.***

We compare here the MCP obtained with (a) the current approach of NOGA, (b) Marginal Pricing with fixes, and (c) approximate Convex Hull Pricing.

- First, Marginal Pricing with Fixes leads to a price signal that is strongly correlated with the current MCP calculated by NOGA, but which is consistently higher. This is mainly due to the “fixes” evoked for properly defining which units are “partly loaded” (e.g., properly taking into account ramp conditions), the interaction of pricing with reserve requirements, and the effect on prices of intertemporal constraints originating from the operation of the pumped hydro storage units. Since the cheapest “seemingly partly loaded” unit may turn out not to be actually partly loaded, the true marginal cost of the system is usually substantially higher, which materializes concretely in the figures and the table below.

- Second, as expected, approximate convex hull prices are higher than marginal prices with fixes, because they reflect commitment costs (such as startup and minimum load costs) more accurately in the MCP. For example, the price spikes that can be observed on October 6th occur at periods where a couple of plants are starting up (or starting up at the preceding period). We can also observe that approximate convex hull prices are, on average, notably higher during the peak season from July to September. The reason is that more units need to be committed during summer, leading to higher commitment costs (startup costs and minimum load costs), which are better reflected in the MCP with approximate convex hull price. After inspection and taking October 6th below as a referennce day where approximate Convex Hull Pricing exhibit substantially higher market prices than Marginal Pricing between periods 30 and 45, it turns out that these periods correspond to periods where units with very high start-up costs (compared to the other units) are started up.

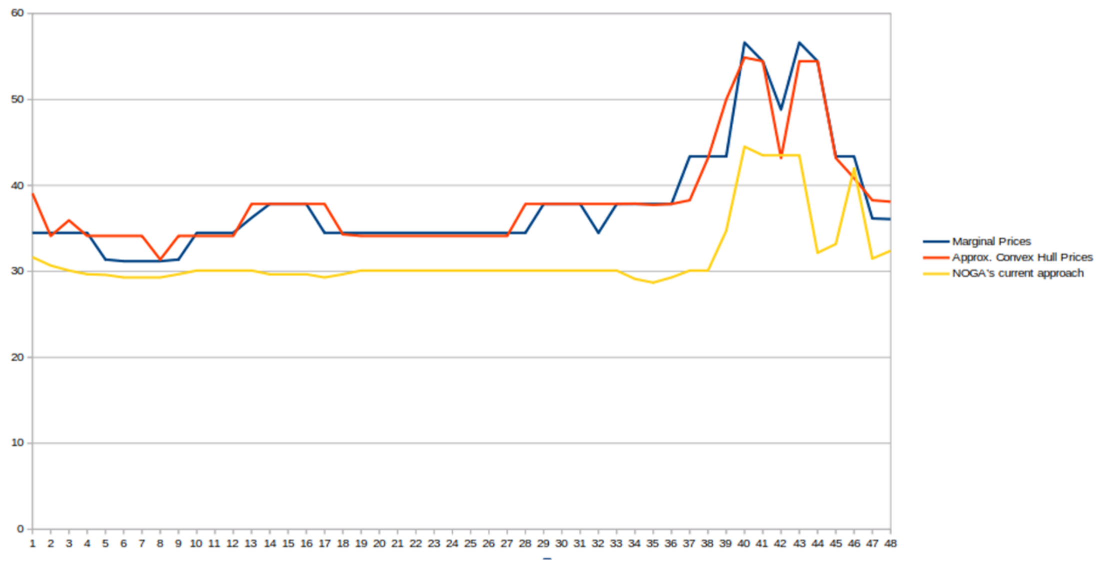


Figure 24: Prices on April 6th, 2021, for the different pricing methods.

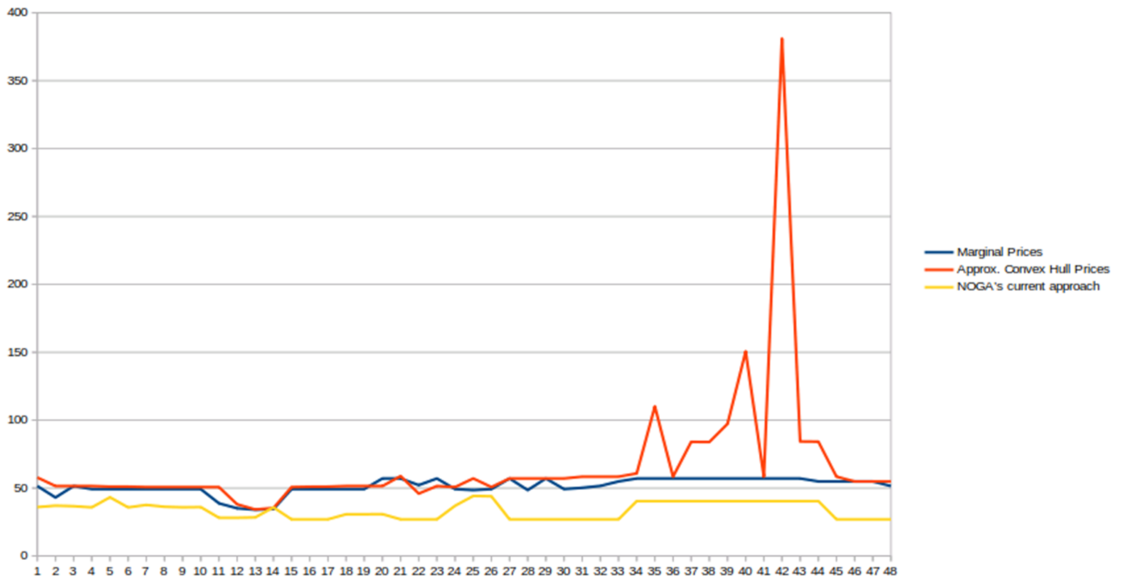


Figure 25: Prices on July 6th, 2021, for the different pricing methods.

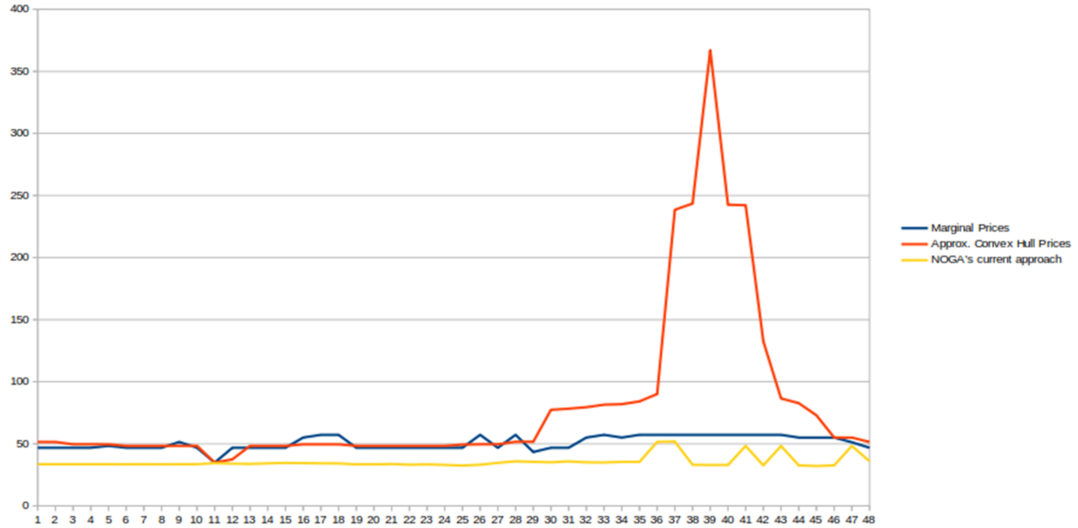


Figure 26: Prices on October 6th, 2021, for the various pricing methods. Prices on October 6th, 2021, for the different pricing methods.

Table 13 Average monthly prices for the different pricing methods.

Month	NOGA ($/MWh)	Marginal Prices with fixes ($/MWh)	Approx. Convex Hull Prices ($/MWh)
January	37.62	47.09	46.91
February	37.02	40.50	43.34
March	33.89	37.57	38.56
April	31.79	37.34	37.42
May	32.85	42.64	45.89
June	35.10	43.90	51.25
July	39.92	53.65	83.61
August	42.71	61.07	97.39
September	39.20	48.16	66.46
October	35.51	43.76	53.10
November	33.65	38.33	43.78
December	36.67	42.47	55.78
Grand Average	***36.33***	***44.78***	***55.45***

2. ***The way to address the non-convexity problem of the MCP prices in Israel including:***
    - ***Convex Hull Pricing***
    - ***Extend MCP***

Non-convexities are introduced by cost structures and technical constraints of specific units such as startup costs and minimum stable generation limits, together with the associated minimum load cost. Due to these non-convexities, optimal prices that ensure zero incurred losses and zero missed sell opportunities for dispatched units do not exist in general.

Various pricing approaches have been implemented in real-world markets to address this challenge, including Marginal Pricing (also called IP Pricing) at CAISO, and Convex Hull pricing (also called Extended Locational Marginal Pricing) at MISO. Marginal pricing do not reflect commitment costs (no-load, start-up, etc) and may hence lead to high make-whole payments. For this reason, MISO uses Extended LMP = Convex Hull Pricing "*to effectively incorporate commitment costs into prices*" (approximating the optimal convex hull prices as closely as possible). PJM uses an "integer relaxation" to compute the day-ahead market prices ("approximate convex hull prices").

In the context of this project, the final recommendation for computing the MCP in the presence of non-convexities (minimum load costs, start-up costs, etc.) is to apply Marginal Pricing with fixes, **also called "IP Pricing"**. The rationale for recommending it over approximate Convex Hull Pricing in the current Israeli context is that:

- IP pricing already leads to MCPs that decrease the need for make-whole payments, achieving one objective targeted by the revision of the MCP calculations. This is an empirical observation based on our realistic simulations of the Israeli system.

- IP pricing is easier to interpret: in each half-hour, these prices correspond to the marginal system cost increase that would result from an infinitesimal increase of the load at that period. Intuition on price formation can hence be obtained by re-running the pricing problem with an increased load of 1MW at the half-hour corresponding to the one with the price being analyzed, and then analyzing the impact of that increase on the optimal dispatch and system costs.

- Approximate Convex Hull Pricing leads to prices that are higher than IP pricing, thus further reducing make-whole payments but also increasing total settlements. The reason is that the price increase resulting from adopting this method applies to the entire production of all pay-as-cleared units, whereas make-whole payments are only decreased for some units: the overall decrease in make-whole payments is offset by the payment increase resulting from the higher prices, leading in the end to higher total settlements.

Even though IP Pricing derives prices by first somehow overlooking the non-convexities and focusing on system marginal costs assuming fixed commitment decisions, the make-whole payments then properly address the non-convexities.

Make-whole payments can be interpreted as some specific "commitment prices" pricing the commitment decisions, which together with the main MCP form a price system with clear economic interpretations, which led experts in the field to consider this approach as an approach of choice even for non-convex markets.

Last but not least, it should be emphasized that strict market monitoring is in all cases strongly recommended to prevent market abuse based on make-whole payments. Strict monitoring policies are notably in place in US markets and in Europe (cf. REMIT requirements for the latter).

3. ***Determine, should the Uplift payments, under the current MCP model and just two players using the model, be taken into consideration within the MCP (SMP) calculation or should it be residual to it? If yes, how to implement it? Should the uplift payments be taken into account in the***

new model? To analyze the influence of uplift payments on retail market where the suppliers buy energy from SO based on market price?

First, let us note that this question directly relates to how non-convexities should be treated. Uplift payments are not needed when there are no non-convexities. On the other hand, recommendations on the treatment of non-convexities directly relate to how uplift payments should be handled: for example, do we want to address the non-convexities so as to minimize the need for uplifts (Convex Hull Pricing approach)?

The recommendation in the frame of this project, taking into account both theoretical elements and empirical results coming from the simulations, is to rely on standard Marginal Pricing (named above "Marginal Pricing with fixes"), which does not attempt to minimize the sum of the uplifts. Make-whole payments are nevertheless paid to units that do not recover their costs via the payments directly based on the MCP calculated in this way.

A second alternative MCP calculation method, is (approximate) Convex Hull Pricing which seeks to minimize the sum of the uplifts, which leads to higher prices and higher final total settlements. The method is, however, based on solid theoretical arguments and is used for example by MISO, the Midcontinent Independent System Operator in the US, and may be an interesting option to contemplate in the future depending on evolutions in the Israeli market.

Finally, let us recall that, in the context of this project, make-whole payments (compensations for "negative profits" / financial losses) are in scope, but opportunity costs are not compensated. Uplifts minimized by Convex Hull Pricing, however, do include opportunity costs in their definition.

In this context, when it comes to if and how *make-whole payments* should impact the MCP calculations, it is important to keep in mind the impact on final settlements: lowering make-whole payments means increasing market prices, which will result in higher total settlements. An extreme example is given by an MCP that is sufficiently high to eliminate the need for *any* make-whole payment, which will result in very high total payments since the MCPs apply to the *entire* production of *all* pay-as-clear units. Marginal Pricing with fixes, already leading to increased prices compared to the current approach applied by NOGA, empirically turns out to be a reasonable compromise between lower make-whole payments and keeping total settlements (i.e. total costs passed to the final consumer) under control.

Concretely:

- *should the Uplift payments, under the current MCP model and just two players using the model, be taken into consideration within the MCP (SMP) calculation or should be residual to it*: Yes, if you are interested in compensating generators for lost opportunity costs then the process by which MCP is computed should be affected as well. The fact that there are two players in the market in your question alludes to market power, but market power is out of scope in this study, so the statement of the previous sentence holds in general for perfect competition, and does not depend on whether there are two (perfectly competitive) players or any number of them. Uplift payments are anyway residual to any process for computing prices, but different approaches affect the MCP differently.

- *If yes, how to implement:* We propose various alternatives in the report. Two of them include IP pricing (fix binaries, then re-run to compute prices), or the linear relaxation approach which is an approximation of convex hull pricing. Which of the two is adopted depends on the priorities of NOGA: if the priority is on keeping financial exposure in the market low, but MWP higher, then IP pricing tends to achieve that. If the priority is to keep MWP low, but with higher MCPs, then (approximate) convex hull pricing achieves that.
- *Should the uplift payments be taken into account in new model?:* Yes, uplifts are accounted for in both of the pricing models that we analyze in the report, namely IP pricing and (approximate) convex hull pricing. This is more so the case in (approximate) convex hull pricing, but it is up to NOGA to decide if they are willing to depress MWPs by increasing the MCP, which is what our proposed (approximate) convex hull pricing method does.
- *To analyze the influence of uplift payments on retail market where the suppliers buy energy from SO based on market price?*: A simple way in which this question can be approached is by computing the ratio of the total annual uplift to the total energy procured by retail market participants (assuming that the compensation for uplifts is fully charged to retail market participants). This gives an indicator of the increase in $/MWh on retail price, if it were retail consumers that were charged with financing uplifts. See also question 4 for additional details.

4. ***The existing model and the way how the MCP price is calculated today – constrained and unconstrained. Should the clearing price be the UNCOSTRAINED as it is today per current regulation or based on CONSTRAINED prices? Is it the right way to pay on two settlement model market the unconstrained MCP in Israel taken into account the list of constraints from current regulation? Should the list of constraints be changed or limited?***

From our understanding, the Israeli electricity market clearing and operation process is currently employing two types of problems, called respectively the constrained and unconstrained models. The constrained version is employed for the purpose of unit commitment and aims at a faithful representation of the system constraints. Then, the unconstrained model, which is a simplified version of the constrained model, is used as a basis for computing unconstrained system market clearing prices that are employed for settlements.

It should be noted that, as a general economic principle, dispatch and prices should be as consistent as possible, and as close as possible to the physical reality of system operation. This means that it is generally better to compute dispatch and prices from the same optimization model. Indeed, this leads to fewer “inconsistencies”, which translates to better economic signals and a reduction of settlement or gaming issues. However, even though the general principle emphasizes that dispatch decisions and prices should be consistent, in practice it may be preferred to depart from full consistency for “political reasons”. We therefore consider that the current approach for determining settlement prices based on the unconstrained dispatch is an acceptable way to address non-economic (i.e. political) constraints. Furthermore, it can be observed in Figure 4 that historically constrained and unconstrained prices computed by NOGA for 2021 were relatively similar in practice for year 2021. Nevertheless, it is not risk-free to use clearing prices that are not fully aligned with dispatch. Attention should be paid in practice to limit as much as possible the features which are “ignored” in the unconstrained optimization compared to the constrained model, in order to keep prices as consistent as possible with the actual dispatch, therewith providing the best possible economic incentives. Indeed, ignoring features which have a material impact over the clearing prices will inevitably lead to settlement issues. For example, if a severe gas shortage limits the actual generation of gas in the (constrained) dispatch calculation but not in the (unconstrained) price calculation, substantial inconsistencies between the dispatch costs and prices may occur. In the short term, such inconsistencies imply that the market does not fully self-finance the computed dispatch, which inevitably leads to “indirect costs”. Our understanding is that such “indirect costs” would be recovered through the NOGA tariff in the Israeli context. On the long term, such inconsistencies imply that the market does not receive the correct investment signals, and thus fails to self-heal.

In view of the discussion above, an immediate need to depart from the current NOGA practice of using the unconstrained dispatch for the calculation of settlement prices is not deemed necessary, if the differences remain in the same range as in our observations. Our practical recommendations for each type of constraint present in the constrained but not in the unconstrained computation are summarized in Table 1. However, should the deviations between constrained and unconstrained prices become significant in the future, one may need to reassess whether the political objectives of the approach are not counter-productive. For example, this would be the case if the approach is intended to reduce the market clearing prices, but, in the short-term, the resulting increase in NOGA tariffs is such that the total cost of consumers is increasing, while insufficient incentives are given on the longer term to reduce the issue.

With respect now to the constraints that are currently part of both the constrained and unconstrained programs, we advise NOGA to maintain these operational constraints in both programs in order to, in the same spirit as the previous recommendations, obtain dispatches and prices that are as consistent as possible and so as to better reflect the current state of the Israeli power system. Among these constraints, we can cite, for example, constraints that are related to system operations, such as:

- Some units are required to operate for a certain number of hours (24 or less);
- Some units are forced to be shut down, even though it would be less expensive to use them in practice;
- Some units are forced to operate at most at a lower level compared to their original maximum capacity;
- Some units are forced to operate at least at a higher level compared to their original minimum stable limit.

5. ***What should be the best model for calculating the MCP while taking into consideration that the Israeli electricity market has in parallel multiple regulations that apply to different IPP's and to IEC. Should there be any updates to the current model for calculating the MCP and all should take into consideration that the target should be minimizing the MCP prices or minimizing the Uplift payments in order to reflect the real cost of energy for Pay as Clear regulation players (including suppliers). (since in the Israeli electricity market the regulator defines when, where and what technologies will be licensed and it's not left for private investor's decisions, and since planning is centralized by the regulator and supported by full capacity payments)***

In view of the developments (particularly on optimal pricing and the treatment of non-convexities), and also the simulation results, Marginal Pricing with fixes is the recommended model for calculating the MCP.

The peculiarity of the Israeli market with different units operating under different regimes (namely pay-as-bid and pay-as-cleared) does not impact this recommendation.

Firstly, assuming truthful bidding, a uniform approach to price formation which considers equally all types of units enables the system operator to properly reflect the cost of energy production (and related economic fundamentals) in the price signal resulting from the MCP calculation. Such an approach supports an efficient usage of the resources (both on the demand and supply side) in the short term.

Secondly, In the Israeli context, it can safely be assumed that, virtually, all units operate under a pay-as-cleared regime for price calculations. The risk with this approach is that – given that units operating under a pay-as-bid regime are incentivized to bid above their true marginal costs to capture some inframarginal rent - price formation can be impacted due to the fact that the merit order considered during the calculations no longer fully replicates the true merit order based on actual marginal costs. Unlike with paid-as-bid settlement, under paid-as-cleared regime, the profit maximization incentives of fringe assets are to bid at marginal costs. In practice, in case market are not sufficiently competitive, market power mitigation measures and market monitoring may be necessary to ensure that price formation reflects the system marginal costs.

Finally, the impact of the particular hybrid setup still materializes in *settlements*, since IPP units operating under the pay-as-cleared regime will receive payments based on the MCP plus make-whole payments where applicable, while IEC units will be paid as bid (some IPP units are also temporarily operating under this regime but will soon move to the pay-as-cleared regime).

6. ***What should be the best way to take into consideration the pumped hydro storage power plants for MCP calculation based on the fact that it is activated by the ISO in order not to affect the MCP and energy market players? Should the system operator take into consideration for***

optimization the real time operation of the pump units for MCP calculations?

Firstly, specific operational decisions taken before the clearing of the day-ahead market should properly materialize as specific technical pumped hydro storage constraints in the so-called dispatch run (constrained run) and ultimately impact the MCP formation according to the optimal pricing principles.

Operational decisions taken after the day-ahead clearing, that will impact real-time operations, should then impact the real-time prices. Essentially, the same principles as for day-ahead MCPs apply, but the pricing run should properly reflect the change in the operational conditions that occurred between the day-ahead and real-time.

As far as we understand the pumped hydro model of NOGA, there is a commitment binary variable which is used for representing the fact that the pumped hydro units need to rest for one hour if they are transitioned, and there are also binary pump-or-produce decisions. The interaction of this model with real time remains somewhat unclear, but we understand that in the Israeli system currently NOGA dispatches units based on their DA schedule, and RT redispatch seems to be based on experience.

An important complexity of pumped hydro resources is that their planning needs to take into account the daily cycle of operation of the power system. This is fine for DA planning if the energy storage capacity of the pumped hydro units is sufficiently low (since a look-ahead of a couple of days can be sufficient for a proper planning of the next day), but becomes somewhat challenging for planning the resource in real time, because the real-time model has a limited lookahead (perhaps only a few hours ahead), which means that the pumped hydro resource is likely to be dispatched inefficiently.

Two possible ways that can be foreseen for integrating pumped hydro into the market model are as follows:

- Centrally dispatched in real time: If NOGA manages the pumped hydro resources, it can either fix the schedules of the pumped hydro resources in the constrained and unconstrained real-time models, or decide an opportunity cost of its own for re-dispatching the pumped hydro unit around a certain range. A piecewise linear convex function can be used if it is preferred to penalize larger deviations from the DA dispatch plan more significantly. The DA model can be used for estimating opportunity costs that can be used as input in this process. If the pumped hydro capacity that can be dispatched in real time represents a significant portion of real-time flexibility, then it is important to not fix the schedule of the pumped hydro resources in real time.
- Decentralized dispatch in real time: If the dispatch of pumped hydro were managed by decentralized market players, then they could be asked to submit their own opportunity costs. But this approach can introduce opportunities for the owners of pumped hydro resources to exercise market power if the pumped hydro resources cover a significant share of the real-time market, thus this approach may not be preferable depending on the specific conditions of the system.

Regardless of which of the two approaches is used for dispatching a pumped hydro resource in real time, having the planning of the pumped hydro resource affecting the formation of DA MCP is deemed desirable. The reason why the above RT dilemma does not emerge in the DA model is that the horizon over which the DA model is optimized is sufficiently deep to properly manage the pumped hydro resource, thus there is no issue of internalizing opportunity costs as a remedy for a short-sighted horizon.

7. ***What should be the best way to take into consideration the BESS or Hybrid (PV & Storage) for MCP calculation based on the fact that it is activated by the ISO in order not to affect the MCP and energy market players? Should the system operator take into consideration for optimization the real time operation of the pump units for MCP calculations?***

The principles that apply to this question are exactly the same as for pumped hydro storage power plants.

Any operational decision known before the dispatch run in the day-ahead time frame should translate into technical constraints that are explicitly taken into account in the optimization. The optimization model solved for the dispatch run should include PV production and storage, together with any technical constraints that are related to it. These constraints should be taken into account both in the constrained and unconstrained run, see the discussion in the answer to the question above.

Operational decisions taken after the day-ahead clearing, that will impact real-time operations, should then impact the real-time prices. Essentially, the same principles as for day-ahead MCPs apply, but the pricing run should properly reflect the change in the operational conditions that occurred between the day-ahead and real-time.

In order to clarify concepts, we consider a sequence of illustrating examples.

Example 1 (fixed pump schedule): Consider a system with two generators, G1 (with a marginal cost of 30 $/MWh and capacity of 150 MW) being dispatched at 100 MWh in the DA market, G2 (with a marginal cost of 50 $/MWh and capacity of 100 MW) being dispatched at 0 MWh. The DA demand in the system is 150 MWh, and the pumped hydro unit is planned in the DA to produce at 50 MW. Suppose that the schedule of the pumped hydro unit is fixed in real time to its DA value. And suppose that the system experiences a negative imbalance (power shortage) of –20 MWh in real time. This leads to an MCP of 30 $/MWh, because G1 is producing at 20 MWh. Thus, the dispatch of the pumped hydro unit is accounted for in real time: if the 50 MWh of the pumped hydro production were not accounted for (i.e. if it were assumed that the pumped hydro is producing 0 MWh), the MCP would have been 50 $/MWh, because the system would have been forced to dispatch G2 at 20 MWh.

Note that this example could happen in Israel: in DA the pumped storage was scheduled to 50MW, but in real-time, the operator chose not to use it.

Example 2 (pumped hydro resource bid at a marginal cost): Consider the same system as in the previous example but suppose that we allow the pumped hydro unit to deviate from its DA setpoint at 40 $/MWh by a non-negative amount up to 30 MWh. If the real-time imbalance is –60 MWh, then the MCP is 40 $/MWh, and is due to the pumped hydro unit being partially activated in real time. Here, too, the pumped hydro unit is accounted for. The difference with example 1 is that its schedule is not fixed, and the marginal cost at which it is offered can set the price. Our point in the response to this question is that coming up with this opportunity cost value of 40 $/MWh can be a complex exercise, but is needed in a static RT economic dispatch model, because the RT economic dispatch model does not rely on a (very deep) lookahead planning horizon. Since the RT economic dispatch model is by design "short-sighted", it is important to properly reflect a "value of water" for the water remaining in the reservoir at the end of the clearing horizon.

8. ***What should be the ideal rule to calculate MCP taking into consideration the restriction on coal generations units in order to not affect market prices (while taking into consideration that coal units are restricted to minimum load normaly or to generate a minimum yearly level of energy)? Does ISO have to take into account the coal units as potential clearing price units based on the current and future levels of coal prices? Suggest the way to do it.***

We understand that, currently, coal units are accounted for both in the constrained and unconstrained models as must-run units which force them to be operated at least at their minimum power. Their actual operational costs are also multiplied by a X factor in order to discourage the model from choosing to increase their power output if natural gas power plants are still available for use, due to environmental reasons. These units are then excluded from the pricing mechanism used by NOGA after the unconstrained run.

Based on these observations, we perceive that the regulator aims to achieve two different objectives with respect to coal:

- **Operations:** Minimizing the use of coal units above their minimum output level and limit such usage to the periods during which natural gas unit capacity or gas availability is not sufficient for covering the system needs for environmental reasons.
- **Pricing:** The market clearing price should not be determined by the price of coal units. Coal units should be excluded from setting the price even if their price is low.

The two proposed pricing methods account for these two objectives by continuing to exclude coal units from the pricing mechanism as the current pricing method used by NOGA.

9. ***Taking into account the current regulation in Israel and rules of the MCP calculation - should the marginal cost come from the next cheapest marginal MW? If not what should be the best way for MCP calculation.***

No, the MCP in a given half-hour should reflect the marginal system cost increase resulting from a marginal increase of load during that period. These MCPs are to be retrieved as the shadow prices (optimal dual variables, or optimal Lagrangian multipliers) of the energy balance condition of each half-hour.

In the simplest market setups, such an MCP *does* correspond to the marginal cost of the cheapest marginal unit. However, in more complex setups with intertemporal constraints (e.g., due to ramp conditions, hydro storage, etc), this may not be true anymore. For example, a unit may seem to be "partly loaded", even though it actually cannot produce more due to its ramp conditions and its production at the previous period. The proper (and standard) way to tackle the challenge of optimal pricing is then to rely on retrieving the shadow price of each energy balance condition, which can easily be done in modern software using state-of-the-art optimizers such as IBM CPLEX or GUROBI.

10. ***Taking into account the current rules of the MCP calculation, should the marginal cost come from the next cheapest marginal MW where energy and spinning reserve are supplied completely? Should it be the next cheapest MW coming from spinning reserve or next cheapest MW coming from next MW complying with reserve and energy supply? How to calculate marginal price in case that it is impossible to supply the spinning reserve requirements?***

I. The MCP for energy in a given half-hour should correspond to the cheapest MW that can be provided to serve an additional MW of load, while still ensuring that all system constraints, including reserve requirements, remain satisfied. This holds in general, and is a sensitivity result of duality theory, and specifically holds in the case of inelastic reserve requirements. In the simplest setups (ramp conditions, storage, etc.), this amounts to identifying the cheapest partly loaded unit, but this method is in general not correct for identifying the system's marginal cost.

More generally, under optimal pricing, the MCP should also correspond to the marginal system cost incurred by a marginal increase of the load. This marginal cost increase is due to a specific change in the dispatch required to meet the additional load, while still ensuring that all system requirements, including spinning reserve requirements and ramp conditions of the units, remain satisfied in the new dispatch. This may require changes in the dispatch and reserve procured by several units, across multiple half-hours, not only at the half-hour of the MCP under consideration.

An interesting corner case is one in which an additional MW of load (if we are interested in the energy MCP) or an additional MW of reserve (if we are interested in the reserve MCP) needs the commitment of an additional new unit, which happens when the capacity of the existing online units is exhausted. In such a case, it is still possible to compute an MCP, but now this MCP depends on the specific pricing method that we choose for dealing with indivisibilities (non-convexities). Two approaches have been proposed in this study:

- IP pricing: in this case, the additional unit is not committed, and the energy price is computed by fixing the commitment of all units. In such an approach, there will be a tendency to ignore the startup cost of bringing an additional unit online, thus the computed MCP will tend to significantly underestimate the actual incremental cost of covering an additional MW. This is coherent with the general tendency of IP pricing, which is reported in the main study, to keep prices low.

- (Approximate) convex hull pricing: in this case, the linear relaxation of the model is run in the pricing / unconstrained run, which means that startup cost will be represented in the model. It will still likely be underestimated, because the linear relaxation model is allowed to "partially” turn a unit on, and thus incur only a fraction of the startup cost, but at least it is somewhat represented instead of being overlooked altogether. This will in general mean higher prices (as reported in our main analysis), and it is up to NOGA to decide if this is desirable, or if they prefer to keep market prices low.

II. If the spinning reserve requirement cannot be met anymore in case of a marginal load increase, it means that this load increase is not technically feasible under the standard constraints imposed to the system. Such a situation corresponds to the orange point on the extreme right on Figure 27. In such a case, one can still define a marginal system price, which will correspond in that case to any value between the system cost decrease that would result from a marginal decrease of the system load (i.e. the left-side derivative of the total system cost function) and infinity (if load shedding is a hard constraint), or the penalty value used for involuntary load shedding (if load shedding is penalized at a very high penalty value). In a simple setting where time periods are independent and there are no ramp constraints or other complicating operational constraints, the MCP becomes equal to any value between the marginal cost of the marginal unit and the penalty value of involuntary load shedding. If we enter strictly into the region of involuntary load shedding (i.e. not the point where we just start curtailing load involuntarily, but where we are actually shedding a non-negative value of load involuntarily), then the MCP becomes equal to the penalty value of involuntary load shedding.

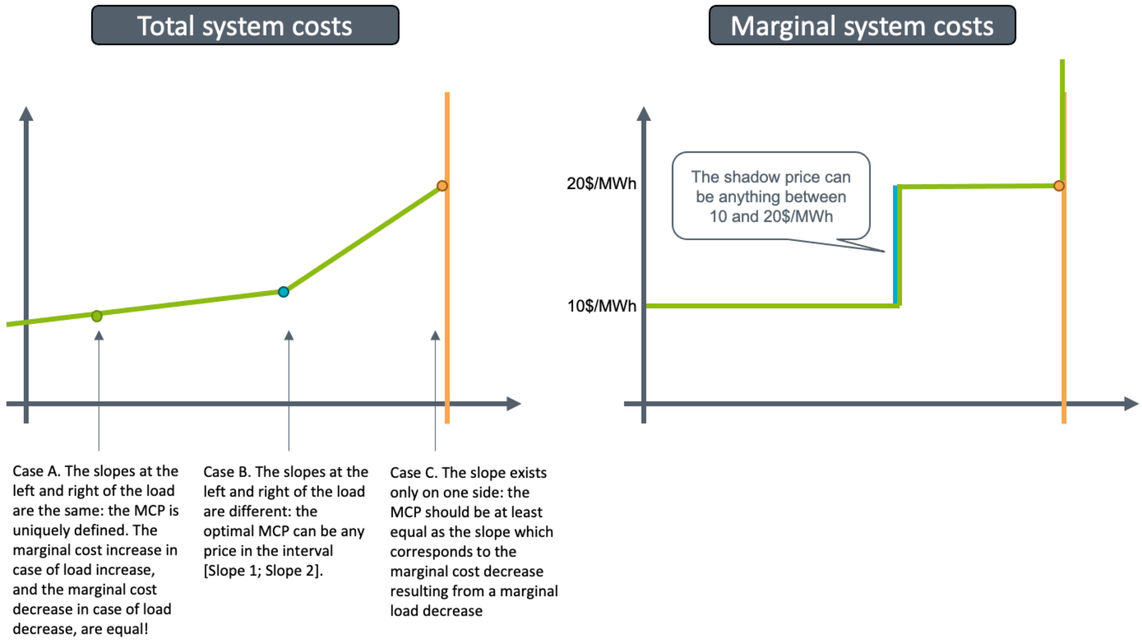


Figure 27: Total cost and marginal cost of a system with a piecewise linear cost function. At the breakpoints where we move from one technology to another, marginal cost is any value between the marginal decrease in cost due to a marginal decrease in load, to a marginal increase in cost due to an increase in load.

In cases of reserve curtailment, and when reserve requirements are a hard system constraint, it is typically the case that the system is facing scarcity. In case there is price-responsive demand in the system, the price is typically set at the valuation of this demand. In case involuntary load shedding (if the coverage of reserve is prioritized over serving demand), price is typically set at an administratively determined value of lost load. Standard practice in US markets (but also recent developments in Europe) favor penalizing the inability to fully cover reserve demand at a value of reserve determined by an **operating reserve demand curve** (ORDC). This process has evolved considerably in recent years: (i) original implementations penalized failure to cover demand by a single penalty parameter, which was decided administratively, and which set the price for reserve (and uplifted the price of energy) during periods of reserve shortage; (ii) Texas then made the first step towards introducing an ORDC based on VOLL and LOLP; (iii) numerous US ISOs followed suit by either introducing stepped ORDCs or ORDCs based on VOLL and LOLP, like in the case of ERCOT. This ORDC then drives the equilibrium price of reserve, during periods of scarcity when the system is unable to fully cover reserve demand. The Belgian regulator has pioneered the implementation of scarcity pricing in ORDC in Europe, inspired by the Texas example [16, 17].

In order to distinguish these different cases, we illustrate them through different simplified examples:

Example 1 (enough capacity in an energy-only market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 800 MW. Reserve requirements are zero. The MCP is 50 $/MWh.

Example 2 (just enough capacity in an energy-only market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 1000 MW. Reserve requirements are zero. The MCP is any value between 50 $/MWh and +infinity $/MWh.

Example 3 (insufficient capacity in an energy-only market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 1100 MW. Reserve requirements are zero. The MCP is undefined, because the problem is infeasible.

Example 4 (involuntary load shedding in an energy-only market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 1100 MW. Reserve requirements are zero. There is a penalty of 1000 $/MWh for involuntary load shedding. The MCP is 1000 $/MWh.

Example 5 (enough capacity in an energy+reserves market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 800 MW. Reserve requirements are 100 MW. The MCP is 50 $/MWh.

Example 6 (just enough capacity in an energy+reserves market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 800 MW. Reserve requirements are 200 MW. The MCP is any value between 50 $/MWh and +infinity $/MWh.

Example 7 (insufficient capacity in an energy+reserves market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 800 MW. Reserve requirements are 300 MW. The MCP is undefined because the problem is infeasible.

Example 8 (energy shortage in an energy+reserves market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 800 MW. Reserve requirements are 300 MW. There is a penalty of 1000 $/MWh for involuntary load shedding. The MCP is 1000 $/MWh (and there is a reserve price of 950 $/MWh).

Example 9 (reserve shortage in an energy+reserves market): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 800 MW. Reserve requirements are 300 MW. There is a penalty of 1000 $/MWh for involuntary reserve shedding. The MCP is 1050 $/MWh (and there is a reserve price of 1000 $/MWh).

Example 10 (penalizing energy shortage more than reserve shortage): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 800 MW. Reserve requirements are 300 MW. There is a penalty of 1000 $/MWh for involuntary reserve shedding, and a penalty of 2000 $/MWh for involuntary load shedding. The MCP is 1050 $/MWh (and there is a reserve price of 1000 $/MWh).

Example 11 (penalizing reserve shortage more than energy shortage): the generation mix in the system has a capacity of 1000 MW, a marginal cost of 50 $/MWh, and a demand of 800 MW. Reserve requirements are 300 MW. There is a penalty of 2000 $/MWh for involuntary reserve shedding, and a penalty of 1000 $/MWh for involuntary load shedding. The MCP is 1000 $/MWh (and there is a reserve price of 950 $/MWh).

11. ***Does the calculation of the MCP should be based on constant unit commitment - without changes of unit mix for each demand? How to deal with cases where in order to supply the next MW the startup of the additional unit is required?***

With Marginal Pricing with fixes (CAISO approach, also named “IP Pricing” in the academic literature) which is the recommended approach for NOGA, the MCP is indeed based on a constant unit commitment and for given loads over the day-ahead clearing horizon, the unit mix should not change when the MCP is calculated.

In case the start-up of an additional unit is required in order to supply the next MW, this implies that it is technically infeasible to supply that extra MW under the current unit mix, and the pricing will instead be based on cost *savings* of serving 1MW *less*. Considering the system obtained after fixing the unit mix, this corresponds again to the orange point on the extreme right of Figure 27. In such a case, it is still possible to compute an MCP, but now this MCP depends on the specific pricing method that we choose for dealing with indivisibilities. Let us focus on the recommended pricing approach, namely IP pricing (Marginal Pricing with fixes): in this case, the energy price is computed by fixing the commitment of all units, and intuitively, looking at the left-hand side of the orange point on the extreme right of Figure 27, to measure the marginal costs savings of serving 1MW less (instead of the cost increase of serving 1MW more). Any price equal or above this marginal cost saving will be a valid price.

12. ***How to calculate the MCP price taking into consideration Demand Side Management?***

Demand-side management materializes in the day-ahead market as price-sensitive demand bids which are equivalent to “supply bids with a negative supply quantity”, similar to downward bids already used by NOGA.

Demand-side bids as well as downward bids are allowed to set the price under standard marginal pricing.

13. ***How should ancillary services be taken into consideration when calculating the MCP for energy? What should be the calculation of MCP for ancillary services?***

I. Calculating the MCP for energy is still achieved by retrieving the so-called shadow prices of the energy balance conditions (the optimal dual variable values / optimal Lagrangian multipliers), whether or not the system constraints include ancillary services requirements such as upward and downward spinning reserve requirements.

If ancillary services are in scope, the MCP will correspond to the marginal system cost incurred by a marginal increase of the load, where the marginal cost increase is due to a specific change in the dispatch required to meet the additional load, *while still ensuring that all system requirements, including ancillary services requirements (e.g., spinning reserve requirements) remain satisfied. Ensuring that the ancillary services requirements remain satisfied may require* changes in the dispatch and reserve procured by several units, across multiple half-hours, not only at the half-hour of the MCP under consideration.

II. The same principles as for the optimal pricing of energy apply when computing reserve prices: the reserve prices correspond to the marginal costs of adding one MW to the reserve requirements (or marginal savings resulting from a decrease by 1 MW of the reserve requirements). The MCP for each of these ancillary services can be obtained, as the MCP for energy, by querying the "shadow price" of the balance condition of the ancillary services. State-of-the-art optimizers such as IBM CPLEX and GUROBI can straightforwardly be used to compute these MCPs.

14. Should the MCP calculation take into consideration the must run units in order to calculate the market price? Does it reflect on MCP prices?

With the exception of coal units, analyses and simulation results show that all units should be considered in the MCP calculation, see more details on this topic in the answer to the question on the usage of the constrained and unconstrained models. Their marginal cost can set the price.

The very peculiar status of coal units, which are dispatched above minimum load only as a last resort in order to avoid load shedding, is the reason why they are excluded from the MCP calculation.

15. To check that Convex Hull Pricing Model could be the best MODEL in order to calculate MCP where it will reflect in the best way:

- ***Minimization of the Uplift level for market players based on MCP model within current regulation in Israel***
- ***Cover the real production (generation) cost paid according to MCP model***
- ***Reflect the costs if resources must be committed to manage a constraint but the constraint is no longer binding in the dispatch after the recourse have been committed.***
- ***The right signal to the MCP Model current and future players that should start to operate commercially in 2022.***

Convex Hull Pricing (approximated in the simulations) appears to provide a very good tradeoff between high prices (which imply low make-whole payments but high final settlements) and high make-whole payments (which imply low prices and low final settlements). However, Marginal Pricing taking into account the fixes recommended during the study provides: (a) prices very close to the approximate convex hull prices, (b) that are easier to explain based on sensitivity analysis (marginal cost of serving an additional MW of load / reserve requirement). For this reason, Marginal Pricing with fixes is our main recommendation.

16. ***Some producers have long term Gas Take or Pay (TOP) obligation. Based on that obligation the IEC, IPPs units may be scheduled on a daily basis. How Gas TOP should be taken into consideration, if any, during calculation of the MCP price***

As a general matter, with the exception of coal units, all other technologies should be treated on a level playing field in the optimal pricing method. The marginal costs of gas-fired units should be properly reflected in the input data of the market clearing algorithm which is used for calculating the MCP. The marginal cost of gas-fired units can either be directly the cost of fuel (in case there exist a liquid spot market for gas), or can be derived from other contractual arrangements otherwise.

In case a total volume of gas is purchased on a yearly basis under TOP obligation, the unit has acquired a fixed volume of gas for a given price and needs to reflect the cost of such a TOP contract in its daily bidding strategy. This means taking into account forecasts of the market situations for the rest of the year. For example, if by the end of the year, much more gas is available under the TOP contract than what the operator estimates necessary, the gas-fired unit has access to a virtually free surplus of gas (because it is available at a sunk cost) and may therefore bid at very low cost.
The general principles applicable to a gas unit which has a fixed yearly volume of gas available at a fixed yearly cost (without the possibility to buy more gas or to resell it on the spot) are similar to those of seasonal storage (e.g. Norvegian hydro dams), where the opportunity cost of selling short-term is a function of the ability to sell at better or worse prices in the long-term, and the “value of the storage” depends on this inter-temporal arbitrage much more than to the actual TOP prices.

17. ***Does the calculation of the MCP should take into account the no-load and start-up cost? If yes, what should be the best way of performing that? How to share the startup cost if taking into account during the optimization period?***

Essentially, two MCP calculation methods have been proposed, with a preference for Marginal Pricing with Fixes:

- Marginal Pricing with fixes (recommended): start-up and no-load costs do not impact the optimal prices but impact the optimal commitment schedules of the units. Make-whole payments are needed in case these costs (start-up costs and minimum load costs) are not being recovered via the payments based on the this IP MCP.
- Approximate Convex Hull Pricing better reflects start-up and no-load costs in the MCP, but leads in the simulation to even higher prices than Marginal Pricing with fixes, lowering the need for make-whole payments but increasing final total settlements. This is the recommended standard approach in case one seeks to better reflect commitment costs in the MCPs.

The final recommendation is however to opt for Marginal Pricing with fixes, as it provides prices that are easier to interpret and present favorable properties in terms of a trade-off between high MCPs and high make-whole payments.

18. ***The needs to put the cap for MAX and MIN MCP by regulator in order to give the right indication for the market and not to affect the market players with over revenues (profit) that should be paid by suppliers operating on Two settlements regulation.***

This discussion is related to a cap on bid prices, since the extreme MCP prices will depend on possible caps on the bid prices. Caps on bid prices (or similar) may be contemplated as a complementary measure but will in no case replace the need for a stringent market monitoring effort. Restrictions on bid prices - if applied - should be set with great care and be sufficiently flexible to enable for unforeseeable market situations (e.g. EU gas crisis).

Appendix B – Optimal Pricing Examples

B.1 Optimal pricing in the presence of ramp conditions

The following example illustrates how optimal pricing business rules can deviate from the heuristic pricing method currently applied by NOGA. We consider a simple two-stage market model in order to illustrate that equilibrium prices can exhibit non-trivial inter-dependencies.

Consider, specifically, a two-period market model with an inelastic demand that is equal to 100 MW in period 1 and 200 MW in period 2. Suppose that the system consists of 2 units:

- A low-cost but ramp-constrained unit with a marginal cost of 20 $/MWh, a ramp limit of 60 MW, and a capacity limit of 300 MW.
- An expensive unit without ramp limitations, with a marginal cost of 50 $/MWh and a capacity limit of 300 MW.

The specifications of the units are summarized in Table 14.

Table 14: Specifications of units in the 2-period example with ramp constraints.

Unit	Marg cost ($/MWh)	Ramp limit (MW)	Capacity (MW)
1	20	60	300
2	50	none	300

The optimal dispatch in this example is for unit 1 to produce 100 MW in period 1 (assume that the unit in period 1 is started up and not limited by its ramping limit from period 0 to period 1), and 160 MW in period 2. Unit 2 produces nothing in period 1, and 40 MW in period 2. The intuition of the optimal dispatch is that we strive to use unit 1 as much as possible since it is the cheapest among the 2 units. The optimal dispatch is depicted in Figure 27.

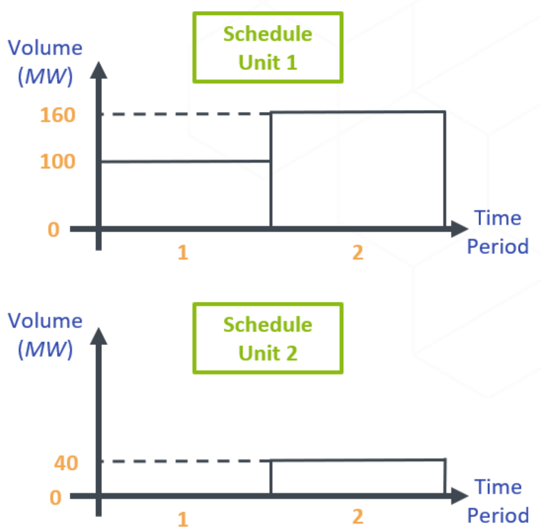


Figure 27: Optimal dispatch of each generator in the 2-period example with ramp constraints.

The pricing approach applied by NOGA would set a clearing price of 20 \$/MWh in both periods. This is due to the fact that unit 1 is the cheaper among the units which are actually producing, but also producing below their nominal capacity.

It turns out that these prices are ***not*** equilibrium prices for the market. The price in period 2 must be 50 \$/MWh, because unit 2 has no ramp constraints and is marginal (or *at the money*), in the sense that it is producing a non-zero quantity that is lower than its nominal capacity. The price in period 1 is –10 \$/MWh, and is driven by the need to induce unit 1 to produce a non-zero yet finite amount of energy at the optimal dispatch. Concretely, a price of –10 \$/MWh in period 1 results in an average price over both periods that is equal to 20 \$/MWh, which happens to be the marginal cost of unit 1. To see why it is necessary for the average price to be equal to the marginal cost of unit 1 over the 2-period horizon, note that:

- If the average price were lower than 20 \$/MWh over both periods, then unit 1 would respond by producing nothing in both periods.
- If the average price were higher than 20 \$/MWh over both periods, then unit 1 would respond by producing as much as possible in both periods, i.e. 300 MW in both periods.

But neither of these production schedules corresponds to the optimal dispatch.

The prices produced by the NOGA methodology are not equilibrium prices, because at a price of 20 \$/MWh in period 2, generator 2 would not be willing to produce 40 MW. The reasoning presented in this example is further analyzed in [2].

B.2 Optimal pricing in the presence of hydro

Hydro resources allow us to move energy around from periods when the system is more loaded to periods when the system is more comfortable. The general effect are prices that are more equalized across time periods. In the limit case where hydro has no operational limits (pump capacity, production capacity, energy storage capacity), energy prices are ***guaranteed*** to be equal throughout the market clearing horizon. To see this, note that a hydro resource without operational constraints will “arbitrage away” any temporal price differences. Put differently, if the price is not constant over time, a perfectly flexible hydro unit could make infinite profit. In the case where hydro has efficiency losses, prices are not equal across periods, but their ratio tracks the efficiency of the pumped hydro storage. We clarify these points by considering two examples. Both examples are sourced from [2].

Example B.2.1: Consider a market with two units and an unlimited hydro unit. The thermal units of the system have the following characteristics:

- Generator 1 is a cheap generator with a marginal cost of 10 \$/MWh and a nominal capacity of 60 MW.
- Generator 2 is an expensive generator with a marginal cost of 50 \$/MWh and a nominal capacity of 100 MW.

As in the case of Section B.1, for the sake of illustration we consider a two-period market, where the demand is inelastic to price and equal to 50 MW in period 1 and 100 MW in period 2. We assume that the market model requires the hydro unit to be neutral, meaning that the hydro unit has to store exactly as much energy as it releases over the two periods. One optimal dispatch is the following, and is presented graphically in Figure 28:

- In period 1, generator 1 produces 60 MW, generator 2 produces 30 MW, and the hydro unit pumps / stores 40 MW of energy, which is the leftover amount of energy once the entire demand of period 1 is covered.
- In period 2, generator 1 produces 60 MW and the hydro unit produces 40 MW, which is the amount that is stored in period 1.

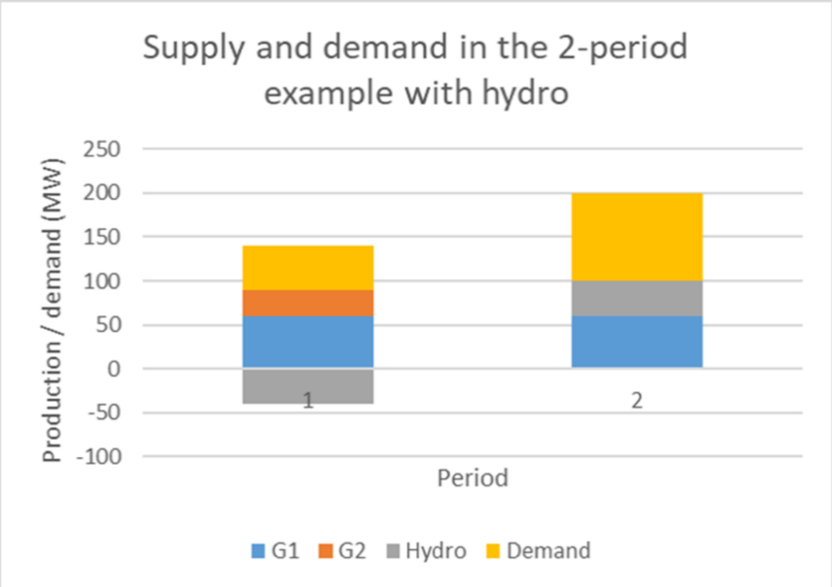


Figure 28: Dispatch of resources in the two-period market model of Example B.2.1.

According to the pricing methodology currently adopted by NOGA, the price in period 1 would be 50 $/MWh (because unit 2 is the cheapest unit that is producing a non-zero quantity below its technical maximum), while the price in period 2 would be 10 $/MWh (because unit 1 is the only unit producing a non-zero quantity).

These cannot be equilibrium prices, because given these prices the hydro unit would store an arbitrary amount of energy in period 1 and release this energy in period 2, whereas the optimal dispatch is for the hydro unit to only store 40 MW in period 1. In order for the hydro unit to follow this optimal dispatch voluntarily, the price in both periods has to be equal, so that the hydro unit is indifferent between any dispatch sequence over both periods (including the optimal one). And the price in period 1 must equal 50 $/MWh, since unit 2 is at the money in period 1, thus the optimal price has to also equal 50 $/MWh in period 2 (and not 10 $/MWh, which is the price that would occur if one were to apply NOGA's current methodology).

Example B.2.2: We now proceed to consider a two-period market model with a hydro unit that exhibits losses. The thermal units in this example are identical to those of Example B.2.1. On the other hand, the hydro unit exhibits an efficiency of 80%, meaning that for every MWh of energy that it consumes for pumping water it is only able to recuperate 0.8 MWh when releasing that water in order to produce electricity. The demand is price-inelastic and equal to 50 MW in period 1 and 100 MW in period 2, as in Example B.2.1.

In contrast to example B.2.1, now there is a unique optimal solution. Generator 1 produces 60 MW in period 1, and the hydro pump absorbs 10 MW. In period 2, generator 1 produces 60 MW, the hydro unit produces 8 MW, and generator 2 covers the remaining demand by producing 32 MW. As in the case of Example B.2.1, the cheap unit is used as much as possible. But, in contrast to Example B.2.1, the unique optimal dispatch of unit 2 is to not use this unit at all in period 1, because if we would dispatch it, then the energy would be stored in the hydro reservoir, and only 80% of this energy would be recovered in period 2. It is thus preferable to use the energy of unit 2 directly in period 2, so that none of it is lost in the pumped hydro conversion cycle.

The pricing methodology of NOGA dictates a price of 10 $/MWh in period 1, because the cheap unit is the only one that produces in this period. The NOGA price in period 2 is 50 $/MWh, because unit 2 is the cheapest one producing a non-zero quantity below its nominal capacity. This is **not** an equilibrium price sequence, because the hydro unit would have an interest in pumping an unlimited amount of water in period 1 and releasing the stored energy in period 2, which is clearly not the optimal dispatch.

Instead, the price ratios of periods 1 and 2 should correspond to 0.8, which exactly matches the efficiency of the hydro unit. And since the price in period 2 is necessarily 50 $/MWh, as unit 2 is at the money during this period, the price in period 1 must equal 40 $/MWh. These prices can be retrieved as “optimal dual variable values” related to the balance conditions, or alternatively from the dual and KKT conditions of the problem, as described above to explain the price of -10$/MWh in Section B.1.

The examples of Appendix B illustrate that optimal pricing can exhibit intricate behavior, even in very simple settings of convex market models. The most reliable countermeasure against this complexity is to use commercial mathematical programming software, which is designed to retrieve such optimal prices as part of the output that is computed from the algorithm that solves the dispatch problem. Thus, optimal prices are computed “for free”, along the way of computing the optimal dispatch of the system, even for highly complex and large-scale market models. Experience from US market operation has proven this to be a viable technique, both on the technological front, as well as in terms of practical business considerations.

Appendix C – Key forward model updates

The key updates for the forward-looking analysis are as follows:

- **Demand projections of the Israeli power system.** Annual demand rises respectively from 79 TWh in 2024 to 82 TWh in 2025 and 83 TWh in 2026 Hourly demand projections provided by NOGA are used for the period 2024-2026.
- **Projected evolution of the Israeli power fleet and its characteristics.** The Israeli power system is projected to undergo adjustments in its power fleet composition. In particular, the main changes consist of a) Decommissioning of 912MW of gas power plants in 2023, b) Decommissioning of coal plants MAORDAV_1 – MAORDAV_4 in 2025 resulting in a total reduction of installed capacity by 1,440 MW, c) Conversion of coal plants MAORDAV_5 – MAORDAV_6 and RUTEN_1 – RUTEN_4 to steam gas over the period 2024-2026 representing a total installed capacity of 3,400 MW, d) Commissioning of new OCGT plants ETGAL and ZOMET 1 – ZOMET 3 in 2023 with a total capacity of 582 MW and MRC 1 and MRC 2 in 2024 with total capacity of 232 MW, e) Commissioning of new CCGT plants SOREQ 2 and ASHDOD DES in 2024 with total capacity of 187 MW, f) Commissioning of 2 hydro pumped storage plants, KOHAV 1 and KOHAV 2, with a total capacity of 344 MW in 2024. Commissioning of another hydro pump storage unit, MANARA, in 2026 with an installed capacity of 156 MW. And commissioning of a 4 hours battery storage with 300MW in 2026, and g) Increase of renewable generator installed capacity to 5,382 MW in 2024, to 6,442 MW in 2025 and to 6,764 MW in 2026.
- **Update of the unit implementation.** The implementation of the different type of units for the forward exercise has been updated to reflect the anticipated evolution of system conditions. In particular, a) for IPP units, bids and bilateral schedules have been revised based on data provided by NOGA, b) for IEC units, variable costs and start-up costs of several units have been adjusted in accordance with information provided by NOGA and fuel prices have been updated to reflect latest expectations, c) for RES units, hourly generation profiles provided by NOGA was considered.
- **Update in unit ownership and regulation.** In 2021, a substantial portion of the power fleet was under the ownership of IEC and all were dispatched according to their operating costs. However, Israel is in the process of transferring ownership of some of these plants from IEC to IPPs. Consequently, we have revised the pricing regulation of these plants in the model and about 20 plants are considered under pay-as-clear regulation in the period 2024-2026.
- **System constraints.** In accordance with the data provided by NOGA, the following system constraints were updated in view of the forward modeling exercise: a) We have updated the requirements for system reserves increasing to 500MW upward reserve in 2024 and 600MW in 2025 and 2026, b) We have implemented a Specific environmental constraints on coal plants based on the

expected shutdown schedules provided by NOGA, c) We implemented a daily gas consumption limit of 1,800,000 MMBTU and a maximum hourly gas consumption limit of 75,000 MMBTU, d) The forward model includes forecasted schedule of maintenance outages for the different plants, and e) The forward model accounts for some random outages of the different units.