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# Excess Supply DR Pilot 2018 Summary and Findings (Public Version)

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## 1 Acknowledgements

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## 2 Executive Summary

This report summarizes the market context, project objectives, technical results and lessons learned for the Excess Supply Demand Response Pilot (XSP) from 2015-2018. The pilot underwent some rule changes in 2018, and this report includes a description of the original as well as new rules.

### Background

California is rapidly making a transition towards a low carbon electric grid. This transformation and the rise of renewables, particularly solar, presents new challenges for grid operators. One challenge is an oversupply of renewable generation in the middle of the day, when supply exceeds customer demand. The two dominant tools in the California Independent System Operator's (CAISO's) toolbox today to mitigate oversupply conditions include either curtailing renewables or exporting them using the real time energy market, the Energy Imbalance Market.<sup>1</sup> A second challenge associated with oversupply is increased ramping needs. The primary tool for the CPUC to solve ramping issues includes time-of-use (TOU) pricing where retail rates are aligned with wholesale grid conditions. However, retail rates are not always aligned with wholesale grid conditions because rates change much more slowly than the wholesale market evolves.

With additional renewable resources coming online, additional measures will be needed. The XSP tests a potential tool to address renewable integration challenges, through assessing the ability of demand response participants to increase their loads above typical use in response to periods of oversupply.

The two figures below demonstrate current challenges the pilot is working to mitigate.

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<sup>1</sup> Examples of energy policies to manage oversupply include: curtailment, exports, demand response, alignment of time-of-use (TOU) rates with the wholesale market, electric vehicles charging at times that align with grid needs, additional flexible resources, and exploring policies to reduce minimum operating levels for existing traditional generators.

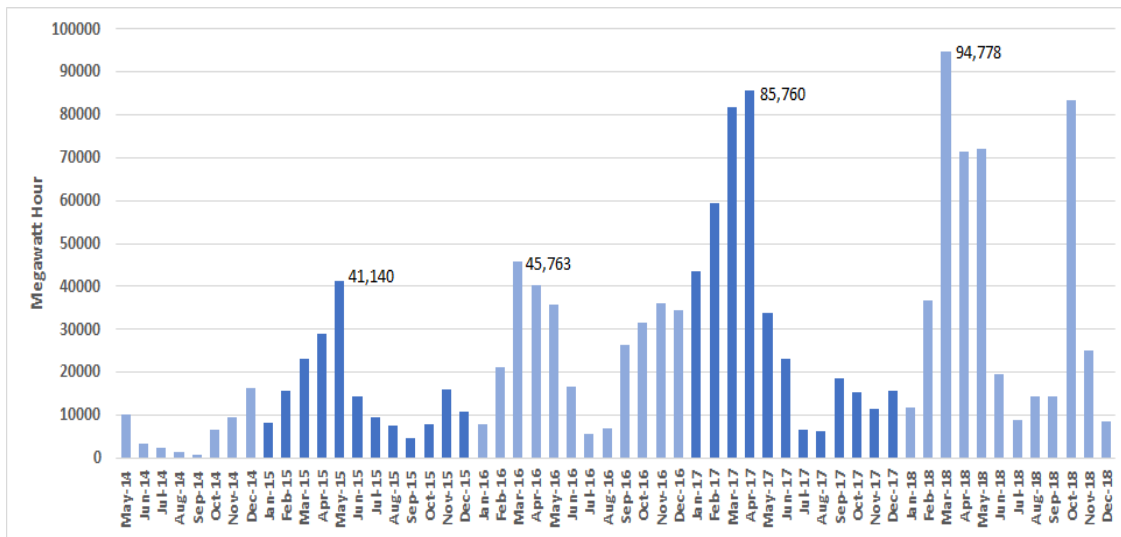


Figure 1: Renewable Curtailment<sup>2</sup>

| Year  | Quarter | MWh     |
|-------|---------|---------|
| 2015  | 1       | 8,860   |
|       | 2       | 3,629   |
|       | 3       | 828     |
|       | 4       | 17,765  |
| 2016  | 1       | 112,948 |
|       | 2       | 158,806 |
|       | 3       | 33,094  |
|       | 4       | 23,390  |
| 2017  | 1       | 52,651  |
|       | 2       | 67,055  |
|       | 3       | 23,331  |
|       | 4       | 18,060  |
| 2018  | 1       | 65,860  |
|       | 2       | 129,128 |
|       | 3       | 19,032  |
|       | 4       | 23,425  |
| Total |         | 757,862 |

Table 1: Reduced Curtailment Due to Exports in the Real-Time Market (EIM)<sup>3</sup>

## Pilot Objectives

<sup>2</sup> CAISO Historical Curtailment. <http://www.caiso.com/informed/Pages/ManagingOversupply.aspx>.

<sup>3</sup> ISO – EIM Benefits Report. <https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ4-2018.pdf>.

The core objective of the pilot is to test the capabilities of price-responsive demand side resources to increase load as a service to the grid during times of oversupply on the transmission and/or distribution lines as well as during periods of negative wholesale market prices.

The pilot was:

- Not designed to require energy neutrality<sup>4</sup>: Just as PDR in the wholesale market today only dispatches resources in one direction (load reduction), XSP dispatches were only in one direction (load increase) without a corresponding load decrease dispatch. Even with the 2018 introduction in the XSP of bi-directionality, load increase and load decrease dispatches were treated independently, and energy neutrality was not required. Though the pilot did not require resources to be energy neutral, pilot participants still paid their full retail rates for the dispatched load increase, which was a disincentive to wasteful energy use as a response to an XSP event.
- Not integrated into the CAISO wholesale market: Without a wholesale market model to use, the pilot was an out of market product, but designed in a manner to potentially enable market integration in the future.
- Not directly triggered by negative prices: XSP events were dispatched based on administrative decisions to test the overall construct of response to excess supply conditions, not based directly on actual grid conditions. This enabled broader testing of participants by allowing more flexibility in when test events were called without having to wait for actual excess supply market conditions. However, starting in 2018 the XSP began using day-ahead oversupply forecasts from PG&E's Short-Term Electric Supply (STES) group as a way of triggering dispatches, and these oversupply forecasts use day-ahead wholesale market prices as an input.

### **Key Accomplishments and Lessons Learned:**

The following are key accomplishments and lessons learned from this pilot:

- Response: The pilot successfully demonstrated the use of participants to respond to excess supply events. In addition, certain participants were also able to respond to load decrease events within the same day.
- Managing Demand Charges: Multiple participants demonstrated their ability to avoid incremental demand charges through their bidding behavior by selecting an availability period that is not coincident with their current monthly maximum demand or peak demand for any of the time-of-use (TOU) periods (e.g., peak and part-peak) so that responding to an XSP event will not set a new monthly peak or TOU peak demands.
- Enrollment: Through the pilot's enrollment process, administrators gained insights into why there was greater interest up front versus actual enrollment. Reasons for decreased enrollment versus interest may be attributable to: education, ability to provide load increase, alternatives which would prohibit participation due to dual participation rules, and the short-term nature of the pilot.

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<sup>4</sup> Energy neutrality means the pairing of an equal amount of load increase and load decrease during a certain interval.

- Customer Classes: There was much more interest from larger commercial participants (customers and aggregators) than from residential or small commercial participants.
- Organizational Roles: The pilot helped in developing and establishing organizational roles and operational handoffs between different groups within PG&E as well as PG&E and a third-party to administer the program.
- Distribution Planning and Operations: The XSP has been working on a new coordination process between the teams developing programs and the distribution planning and operations teams to ensure that operating the XSP does not create local distribution network issues. Any excess supply product can have a positive or negative impact to the distribution system depending on multiple factors, including the location, size, duration, timing, composition, and concentration of the resources. A key concern for distribution planners is that distribution systems were designed to accommodate diverse loads where usage from similar devices, such as HVAC, is somewhat distributed and act independently from each other. Aggregating these small but numerous loads into a biddable product will require participants to react in the same manner at same time, which is not something that was anticipated and could cause issues for distribution planners and operators.

## **Recommendations:**

For initiatives and proceedings examining new DR models,<sup>5</sup> PG&E offers the following product and operational recommendations leveraging the experience of XSP.

### Product Recommendations:

- Grid Needs: Any product should serve grid needs associated with renewable integration challenges and be compensated for the service it provides to the grid based on market prices. The grid needs the product is solving for (e.g. avoiding renewable curtailment, avoiding distribution investments, reshaping load seasonally) should be defined prior to developing the product.
- Market Integration: CAISO market integration should be pursued for XSP if solving for real-time grid needs.
  - A market integrated, geographically granular product that can respond in 15 minutes or 5 minutes may be able to flexibly help with local grid conditions. Such a product could help mitigate local or system curtailment.
  - A non-market integrated product, such as a special rate, that dispatches in hourly blocks may or may not be able to help depending on wholesale market and local

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<sup>5</sup> Both the CPUC's Load Shift Working Group (LSWG) and the CAISO's Energy Storage and Distributed Energy Resources Initiative Phase 3 (ESDER 3) examined load shift or load increase products.

- The CPUC's LSWG explored developing new models of a technology agnostic load shift product. More information is available on the facilitator, Gridworks' website: <https://gridworks.org/initiatives/load-shift-working-group/>
- CAISO's ESDER 3 initiative, among other enhancements a load shift product specific for behind-the-meter energy storage; noting this product may be deferred and reconsidered in the ESDER 4 initiative underway in 2019. More information is available on CAISO's ESDER website: [https://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage\\_DistributedEnergyResources.aspx](https://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_DistributedEnergyResources.aspx)

conditions. However, such a product could help shape the load of an end-use customer more generally.

- Technology Neutral: An excess supply product should be technology agnostic to enable any end use to provide excess supply. We acknowledge that like the existing DR model providing curtailment service today, some technologies may thrive using this new DR product while others may not.
- Not Energy Neutral: While suggested by some participants, an excess supply product should not necessarily be energy neutral, where the pairing of an equal amount of load increase and load decrease during a certain interval would be required. This does not appear to be either feasible in CAISO's optimization today or aligned with grid needs as there may be some days in which a load increase may be needed more than a load decrease product. In addition, as long as participants continue to be subject to retail energy charges, there is a disincentive to wasteful energy use as a response to a load increase event.
- Aggregation Size: Additional discussion is needed regarding aggregation size. The aggregation size will need to find the right balance between the sub-LAP requirement, which is generally considered too large to manage local grid conditions, and conversely too small of an area to aggregate customers. If the ultimate objective of an excess supply product is to also address local distribution system constraints, it could be that a geographically smaller aggregation based on local areas within a sub-LAP may better mitigate over supply at the distribution level.
- Participation Payments: Participation payments are necessary. The related project, the SSP II, as well as feedback from the CPUC LSWG, has provided clear data on the relatively low revenues to be achieved from CAISO market participation based on wholesale energy payments alone. Without a participation incentive, load increase programs cannot be incentivized sufficiently from such energy payments.

#### Operational Recommendations:

- Availability: Periods of availability should be based on grid needs with flexibility to reflect participants' abilities to respond. As part of this, participants should be allowed to specify their availability to provide load increase, though care should be taken to prevent load increase availability from interfering with any other market obligations. For example, a participant that is also providing load reduction for system Resource Adequacy (RA) should not specify an availability period for load increase during the RA availability assessment hours.
- Most Valuable Days and Seasons: Not all days/months are equal in their value to the grid in providing support to reduce excess supply. Current grid conditions indicate that an excess supply product is more valuable to the grid on weekends and during the winter and spring months than on weekdays and during the summer. This is substantially different from the historical perspective that load reducing DR is most valuable during weekdays in the summer. Determining a way to incentivize this will be important to the future development of this product.
- Frequency: Frequency of dispatch should be based on customer abilities. The current XSP pilot recommends a maximum of once per day to align with the one start per day use limitation available to the CAISO's Proxy Demand Resource (PDR) product.

- Dispatch Timelines: Response time of an excess supply event should match grid needs, meaning if the resource is participating in the wholesale market the resource should respond in line with market dispatches and if the resource is responding to distribution planners, the response should match distribution timelines.
- Distribution Planning and Operations: Due to the potential impact of a load increase product on distribution planning and operations, it is imperative that development and operation of this type of product be integrated with distribution planning and operations groups.

## Conclusion and Next Steps

The XSP has been successful in gaining learnings in a number of its key objectives and, in doing so, has directly and indirectly addressed multiple barriers to renewable integration challenges. In addition, these learnings have helped inform ongoing proceedings at the CPUC and CAISO. The XSP is also being looked at and utilized by other groups. For example, site hosts in PG&E's Electric Vehicle Charge Network (EVCN) program can meet the EVCN's load management plan requirement by participating in the XSP. Including EVCN participants in the XSP enables the pilot to incorporate a technology (electric vehicles) and customer classes (smaller commercial and multi-unit residential) that have been absent from the program.

While much has been learned, there are still unanswered questions around what should trigger an excess supply event, the effects on local distribution planning and operations, and the interaction with other DR programs that provide load reduction. Based on feedback and learnings from the XSP so far, and as part of continuing to gain insights into the previously mentioned issues, the following efforts are being planned for the XSP:

- Continue to refine the event trigger mechanism to trigger events when excess supply situations are likely to occur based on actual market conditions; and,
- Continue to provide real-world input into ongoing stakeholder efforts at the CPUC and CAISO;
- Evaluate the value of negative market prices to the incentive structure;
- Continue with the implementation of the EVCN participation option.
- Recruit new participants into XSP to robustly test the new XSP feature set delivered in 2018.

While excess supply events are already occurring and expected to grow in frequency, they are still limited. Because of this, and since there are still open questions that should be resolved prior to developing a large-scale program and which are being tested as part of the XSP, PG&E believes it is reasonable to continue testing this product as a pilot.



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## 3 Introduction

### 3.1 Background

Current California policies, new State renewable energy goals, and penetration of new end use technologies add complexity to future grid needs. A key example of such challenges is the California Independent System Operator (CAISO) is experiencing steep ramps during winter and spring with California’s current Renewable Portfolio Standard (RPS) mandate of 60% by 2030 and 100% carbon-free generation resources by 2045<sup>6</sup>.

There has been much written about the changing net load curve, where the “net load” is the total system load minus the renewable generation. This change from the conventional mid-day peak, due in large part to the increased penetration of renewables, dramatically impacts the system operational needs. This is often referred to as the “duck curve”; however, as PG&E has noted in previous presentations, “there are more than ducks in the zoo.” Figure 2 shows this emerging reality with estimated net load curves for specific days in 2022.

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<sup>6</sup> SB 100: [https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill\\_id=201720180SB100](https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100)

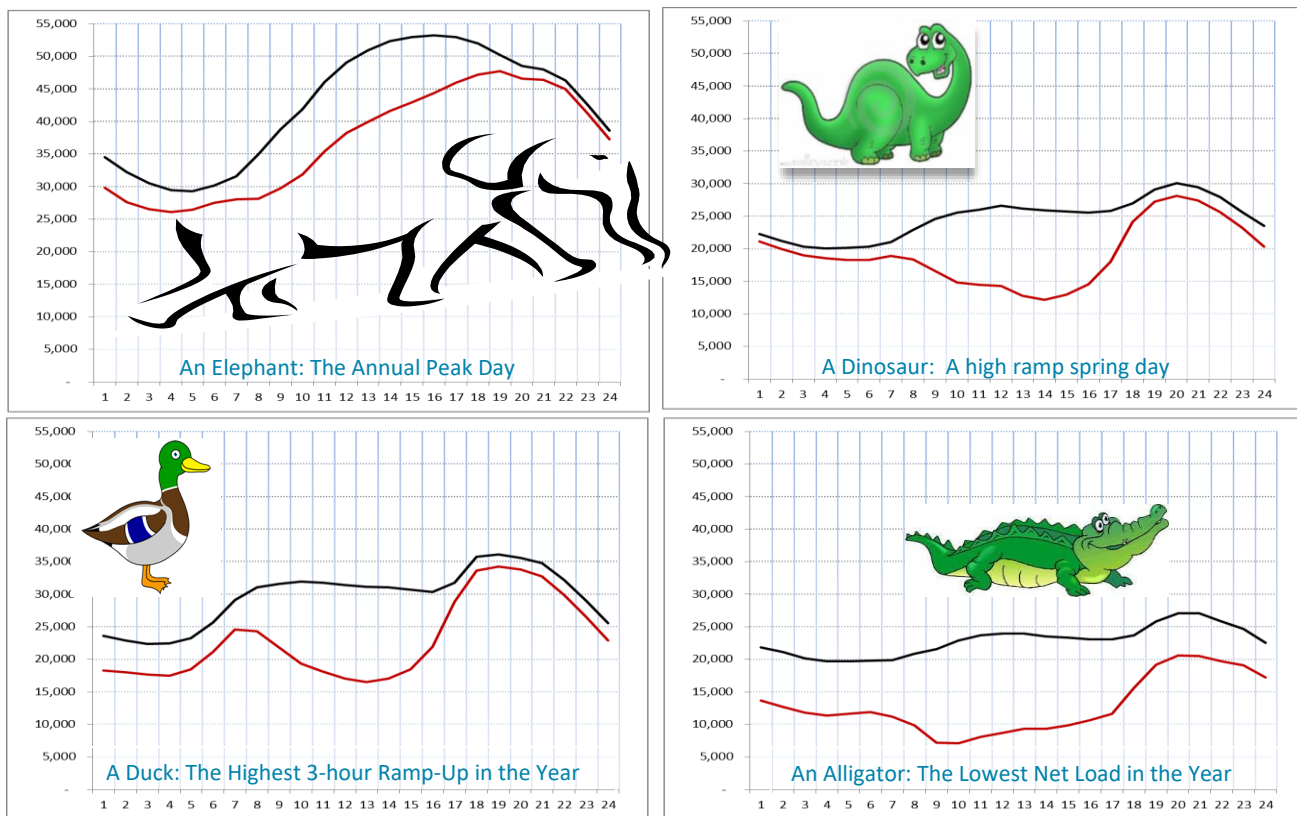
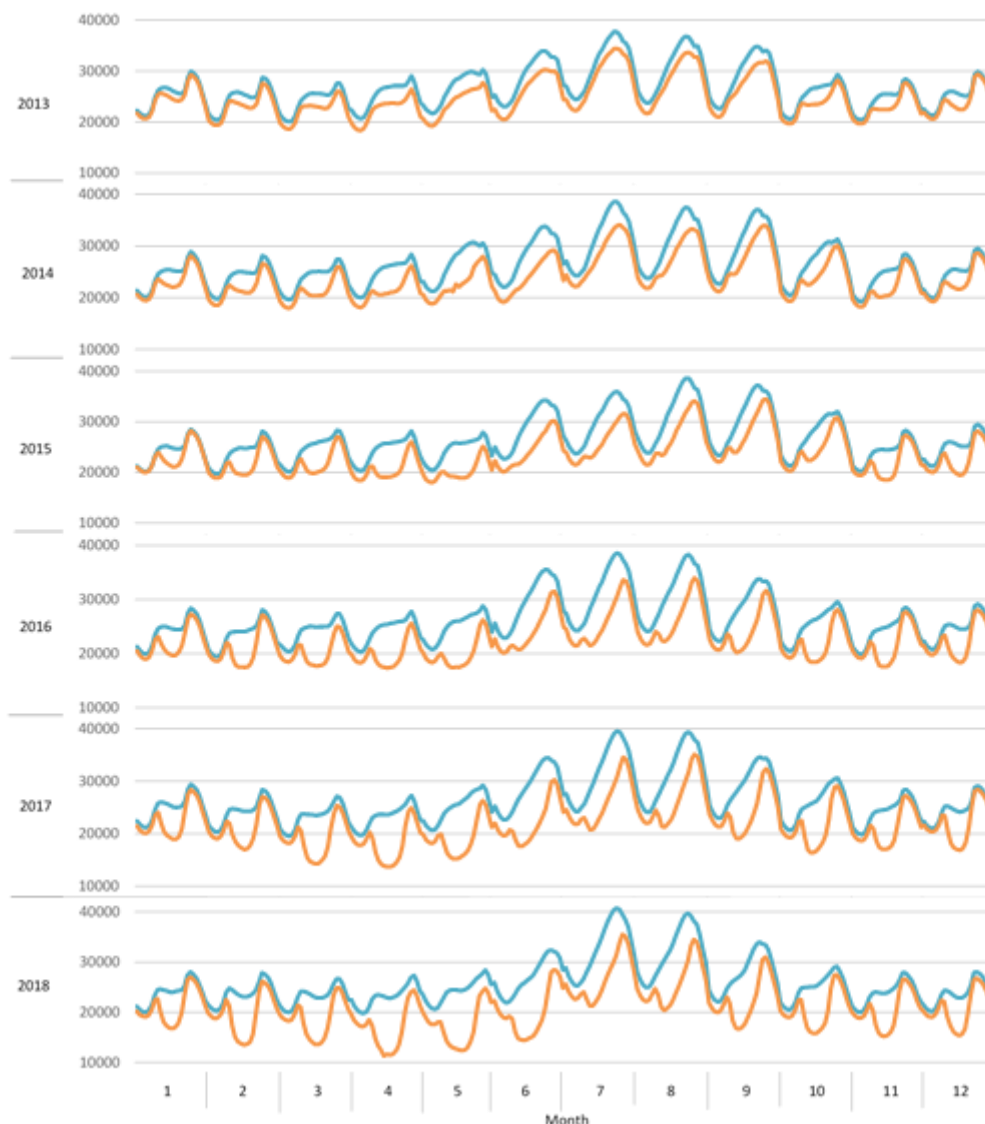


Figure 2: Many Animals in the Zoo

Figure 3 shows the average daily gross and net CAISO system load profile by month for 2013 - 2018. As seen in this figure, not only have the net load profiles changed in recent years, they fluctuate substantially over the course of a year. This demonstrates the importance of a flexible solution that can be adapted to fit the ever-changing load profiles.



*Figure 3: Average CAISO System Gross vs. Net Loads*

These changes in net load, policy, and technology, create challenges to the grid in balancing against the capacity in transmission and distribution and require California to evaluate which market constructs and resources can address future grid needs. Examples of policy tools available to solve ramping issues include time-of-use (TOU) pricing where retail rates are aligned with wholesale grid conditions, exporting electricity during periods of excess supply, and curtailing renewable resources.

PG&E's Excess Supply DR Pilot (XSP) is investigating ways to incentivize customers to shift energy usage on demand as another possible way to mitigate these challenges. In the XSP, demand responsive loads are being considered as one of the many resources that can support in-state economical and reliability needs of the future grid. The XSP is a departure from other offerings in that it asks participants to shift energy usage to consume more energy at certain times to help

mitigate situations of excess supply. By getting customers to shift their energy consumption to align with periods of excess supply, the XSP hopes to demonstrate that customers can actively assist with renewables integration and improve alignment of supply and demand. In 2018, the XSP was expanded to support bidirectional demand responsive loads by giving participants the option to participate in load decrease events in addition to load increase events.

There is currently no mechanism for bidding load-increasing DR into the CAISO market, resulting in this pilot being an out-of-market program with simulated events. PG&E has been working with the CAISO and other stakeholders as part of the Energy Storage and Distributed Energy Resource (ESDER) initiative to expand the Proxy Demand Resource (PDR) product to allow demand response (DR) to provide load-increasing bids in the CAISO market. As of September 2018, the CAISO's proposed load shift product was approved by the CAISO Board of Governors, noting that at the time of the completion of this report the implementation phase has been deferred to at least 2020 with the prospect of revisiting its design. In addition, the CPUC assessed similar load increasing capabilities (i.e., Load Shift) as part of the Load Shift Working Group which published a report of recommendations drawing on lessons learned from the XSP.

The XSP also provides pathways for new technologies. PG&E believes that technologies adopted behind the customers' meters, such as storage or smart devices, have a vital role to serve as grid-responsive assets. DR programs will act as gateways for participants to provide their demand and energy shifts that are tied to when excess supply is occurring. Results of the XSP will help PG&E and the CPUC assess the benefits of DR as a gateway to grid needs and benefits and, in addition, provide an in-depth understanding of the benefits of technologies, like energy storage and electric vehicles.

In addition to traditional demand response that addresses summer peak shaving, new DR offerings must be constructed to meet future transmission and distribution grid needs. PG&E has a history of developing such offerings within pilots and then incorporating the learnings into full-scale programs, including this pilot as well as the recent and related Supply Side II DR Pilot (SSP II)<sup>7</sup>.

### 3.2 Program Objectives

As stated in PG&E's 2018 – 2022 DR Application Supplemental Testimony<sup>8</sup>, the primary objectives of the XSP are to:

1. Inform the design of a future program by conducting field testing of the actions required from PG&E, customers, and third-party aggregators so that load can be increased when excess supply conditions exist;

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<sup>7</sup> The SSP II has been testing aspects of integrating load reduction DR resources in the CAISO market while also providing distribution needs.

<sup>8</sup> A. 17-01-012, Supplemental Testimony titled PROPOSED IMPROVEMENTS TO EXISTING PG&E-IMPLEMENTED PROGRAMS AND PILOTS, Section D, at pp. 2-A2-2 to 2-A2-3 (February 3, 2017).

2. Assess what triggers, other than CAISO energy market pricing, can be used to call events as early as possible to allow a sufficient amount of time to notify participants of an event;
3. Experiment with compensation methodologies to participants and the interactions with retail rates;
4. Factor the local distribution constraints systematically in the XSP's operations to ensure that, when situations of excess supply occur at the CAISO's Sub Load Aggregation Point level, the actions taken by participants do not create congestion on the distribution system; and
5. Explore baseline methodologies and evaluate whether they lead to an understanding of the performance of a DR resource that is asked to consume more energy.

In addition, the XSP has a sub-program that is targeted specifically at participants in the PG&E Electric Vehicle Charge Network infrastructure project.

### 3.3 Regulatory Background

As part of the 2015-2016 DR funding bridge, the Commission approved the XSP in Decision (D.) 14-05-025, and the pilot was initiated in 2016. Since the pilot had been active for less than a year, which did not allow much time for testing, PG&E received approval from the Commission to continue the pilot through 2017 in D.16-06-029 and then from 2018 – 2020 in D.17-12-003. These continuations of the pilot included various rule changes.

### 3.4 Pilot Roles and Responsibilities

The pilot team roles and responsibilities are identified in Figure 4. Both single customers and aggregators are eligible to participate in the XSP. Olivine serves as the pilot administrator enabling participation through the Olivine DER software platform. Olivine provides the primary interface between participant and pilot, including development of informational and educational material, participant recruitment, enrollment and registration; nominations; award and dispatch notifications; meter data aggregation; resource certification; and calculation of settlements and payments. In addition to the pilot sponsor, PG&E is the overall program manager and is responsible for tasks such as leading program design, managing the overall pilot budget, approving informational and educational material, working with Olivine on participant education and recruitment, approving participant applications, developing the quantitative assessment of when to trigger pilot events, and managing meter data delivery to Olivine. PG&E is also responsible for overall policy and strategy development that became the basis for the pilot.



*Figure 4: Entities Involved in the Pilot and their Roles*



## 4 XSP Participation

To participate in the XSP, participants need to meet several requirements for eligibility and enrollment, detailed in this section. For the XSP, the term “participant” refers to the party that enrolls in the pilot and makes decisions related to when to participate and how to respond to events. Participants can be:

- Retail non-residential customers with individual locations that meet minimum load requirements,
- Retail non-residential customers with multiple locations, or
- Third-party aggregators that aggregated a group of individual retail and/or residential customer loads.

### 4.1 Customer Eligibility

The term “customer” refers to the retail end-customer (i.e., the entity that has a service agreement (SA) with PG&E). Initially, the XSP was only open to residential and small commercial customers who were on retail rates that did not include a demand charge component<sup>9</sup>. This was to avoid the possibility of increasing the customers’ demand charges due to responding to a load increase event. However, due to low interest in participation from these customers classes and high interest from larger non-residential customers, pilot eligibility was expanded to include large non-residential customers.

The XSP is open to PG&E bundled retail customers as well as unbundled retail customers who receive energy procurement services from a Community Choice Aggregator (CCA) or Electric Service Provider (ESP).

### 4.2 XSP Resource Composition

The XSP organizes customer locations into aggregations called resources. To poise the pilot for use as a market integrated product in the future, many of the resource requirements mimic how the CAISO defined its proxy demand resource (PDR). While not strictly necessary for the XSP, this resource organization is maintained within the XSP for two reasons:

1. Any future CAISO product that would support increased demand would very likely maintain these resource characteristics; and,
2. Originally, to facilitate multiple participation in the related Supply Side II DR Pilot (SSP II); however, with the addition of the load decrease option in the XSP in 2018, multiple participation is no longer allowed.

An XSP resource is composed of either a single customer location or an aggregation of customer locations. For example, an aggregator can assemble a collection of commercial or residential customers into a resource that can then participate in the XSP. A large customer may also directly enroll one or more locations, if the set of locations meets the eligibility requirements. In general,

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<sup>9</sup> In general, residential and small commercial customers are not exposed to the demand charges.

each participant in the XSP is allowed to enroll a single resource that needed to meet the requirements detailed in the following sections. On a case-by-case basis, participants can enroll additional resources if PG&E determined that the additional resource was unique in some way that is not already reflected in pilot participants and could benefit the pilot. Reasons for allowing additional resources include new customer types, geographic areas, or methods/technologies used to respond to events.

#### 4.2.1 Minimum Load Increase

In the original XSP, resources were required to be able to achieve a minimum of 30 kW load increase for up to 2 hours over a participant-defined 4-hour period. This size requirement was chosen to enable dual participation with the SSP II pilot. Note that this requirement allowed for the participant to achieve this increase at any time of day to meet this requirement. As part of the rule changes to the XSP in August 2018, participants now have to achieve a 30 kW increase for 2 hours during a contiguous 5-hour period between 8 AM – 4 PM. See section 4.3.1 for more information on the performance measurements.

#### 4.2.2 Minimum Load Decrease

The Load Decrease option was introduced as part of the XSP rule updates, that came into effect on August 2018, to enable participants the ability to also be dispatched for load decrease events. Resources partaking in load decrease can be wholesale market integrated under the CAISO PDR product, if the resource can meet CAISO requirements. Regardless, the operations are designed with active wholesale market participation in mind. XSP resources that also elect to participate in load decrease are required to be able to achieve a minimum of 30 kW load decrease for up to 4 hours between 4 PM and 9 PM on weekdays, corresponding to the CAISO system RA availability assessment hours. Upon the publication of the day-ahead market clearing prices, resources whose bids cleared were granted an award and subsequent dispatch.

#### 4.2.3 Single Sub-Load Aggregation Point (sub-LAP)

A sub-LAP is a geographically defined area. As of January 1, 2017, PG&E's service territory is split into 15 sub-LAPs,<sup>10</sup> such as PG&E East Bay or PG&E San Francisco.<sup>11</sup> As with PDR today, all locations within the XSP resource must be located within a single sub-LAP. Therefore, a resource cannot contain locations from both the East Bay and San Francisco. The need for a locational requirement stems from the fact that oversupply concerns may be localized on the transmission and distribution grid. The decision to use the sub-LAP as the area of localization stems from the following:

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<sup>10</sup> The number and boundaries of the sub-LAPs were updated by the CAISO effective January 1, 2017, and prior to that time there were 16 sub-LAPs in PG&E's electric service territory.

<sup>11</sup> PG&E Sub-lap map: [https://www.pge.com/pge\\_global/common/pdfs/save-energy-money/energy-management-programs/demand-response-programs/2018-demand-response/2018-demand-response-auction-mechanism/PGE-Sub-Lap-Map-201703.pdf](https://www.pge.com/pge_global/common/pdfs/save-energy-money/energy-management-programs/demand-response-programs/2018-demand-response/2018-demand-response-auction-mechanism/PGE-Sub-Lap-Map-201703.pdf).

- If excess supply was a specific CAISO market product for behind-the-meter DER, it is reasonable to assume that resources offering the product would be constrained within Sub-LAP regions.
- Sub-LAP data on customers is relatively easily available from PG&E systems.
- Allowed XSP resources to also participate in the SSP II; however, this option for multiple participation was ended in 2018.

Note there is a tension between the sub-LAP being too large of a geographic area to resolve distribution level constraints and too small of a geographic area for enrolling enough customers to meet minimum size requirements. From the perspective of oversupply on the distribution grid, the sub-LAP is likely too large of a regional construct, plus distribution constraints can differ substantially from circuit to circuit which is too granular to be handled at the sub-LAP level. To address these issues, granularity of dispatch at the feeder level would be a better construct. However, in various proceedings and stakeholder processes, in addition to experience gained from working with various parties as part of the XSP, parties have been clear that even at the sub-LAP level, there can be challenges with the size of the potential customer pool, thus making it harder to enroll enough customers to meet a reasonable minimum load. As such, the sub-LAP has been deemed a compromise for the XSP.

#### 4.2.4 Dual Participation

Customers in the XSP are not allowed to participate in any other DR program, including Critical Peak Pricing (CPP) programs (SmartRate and Peak Day Pricing). If a customer already enrolled in another DR program wanted to enroll in the XSP, the customer had to unenroll in the other DR program first. While part of the reason was to prevent XSP participants from being in violation of the CPUC's established rules regarding participating in multiple DR programs (dual participation), the primary purpose was to reduce the administrative burden on the pilot. Administration of the XSP (including dispatches, performance calculations, and settlement calculations) were done by Olivine outside of the PG&E system. As such, there was no direct link between the systems that dispatch pilot events (and calculate the subsequent performance) and those that dispatch other PG&E DR program events (and calculate the subsequent performance). Having to establish and maintain this link would have been manual and an additional administrative burden. Therefore, dual participation was generally not allowed to ensure that there were not conflicting signals between the pilot dispatches and dispatches from other DR programs. Similarly, although not a CAISO-integrated product, customers participating in the XSP also could not be enrolled in a CAISO resource to avoid a conflict between wholesale market and out of market pilot dispatches.

As noted elsewhere, an exception to this prohibition on dual participation existed between the XSP and the SSP II; however, this practice was ended in 2018 with the addition of a load-decrease option to XSP.

#### 4.2.5 Single Load Serving Entity (LSE)

The LSE is the entity responsible for procuring electricity for their customers. For bundled utility customers, the LSE is PG&E. For unbundled / Direct Access (DA) customers, the LSE is an Energy Service Provider (ESP) or Community Choice Aggregator (CCA).

As mentioned above, bundled as well as unbundled utility customers can participate in the XSP. However, while not required for the XSP, keeping consistent with the CAISO rules for PDRs, it was preferred that all enrolled customers in an XSP resource be served by one LSE.

4.3 XSP Rules

Aside from the eligibility requirements enumerated above to enter the XSP, participants have several requirements for qualification and ongoing participation to earn a participation payment. This is outlined in the following figure:

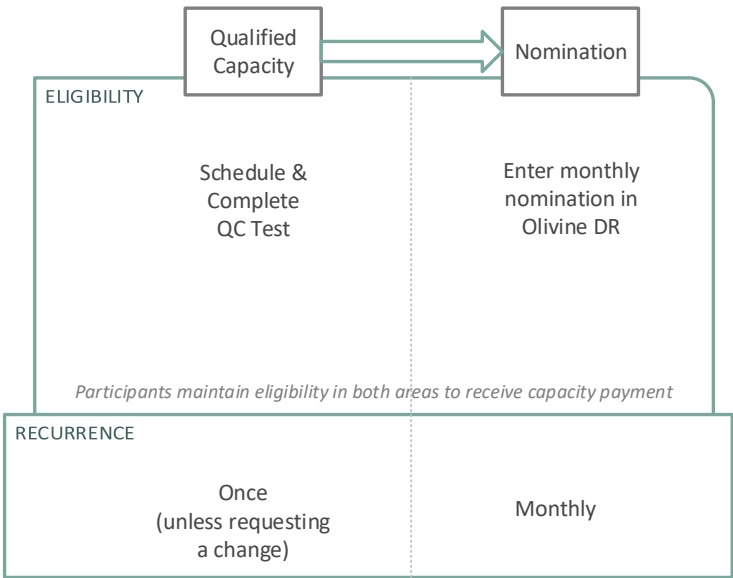


Figure 5: Participant Operational Tasks. Courtesy of Olivine, Inc.

The following sections walk through the various XSP rules, starting with performance methodology as this is a key to participation and drives the result of the qualified capacity test.

4.3.1 XSP Baseline and Performance Methodology

To measure performance, the XSP utilizes the ISO Type 1<sup>12</sup> baseline methodology, which is a long-established baseline methodology set forth by the CAISO for the PDR product. The XSP utilizes the whole-premise meter data (i.e. no sub-metering). The baseline is a “10-in-10” calculation that takes the average of a target number of the most recent similar day-type non-event days, subject to a morning-of adjustment with a ± 20% cap. Below is a detailed example of the baseline calculation process for a trade date where both load increase and decrease events occurred. The

<sup>12</sup> The ISO Type 1 methodology is based on the North American Energy Standards Board (NAESB) Baseline Type-I methodology which is described in the NAESB WEQ Business Practice Standards WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response.

ISO Type 1 baseline methodology is similarly used to measure performance for load decrease events.

1. Identify the target number of previous similar day-type non-event days
  - Day-types are defined as weekdays (Monday – Friday) and weekends/NERC holidays.
  - The target number of days for each day-type are,
    - Weekdays: 10 days
    - Weekends/holidays: 4 days
  - Previous event days are excluded.
  - The maximum look-back window is 45 days.
  - If 10 non-event “Weekdays” cannot be identified within the 45-day look-back window, but at least 5 days can be identified, the baseline is calculated using the available days.
  - If at least 5 non-event Weekdays or 4 non-event Weekends/holidays cannot be identified in the look-back window, the highest usage prior event days within the look-back window are then included as needed to reach the minimum number of days.

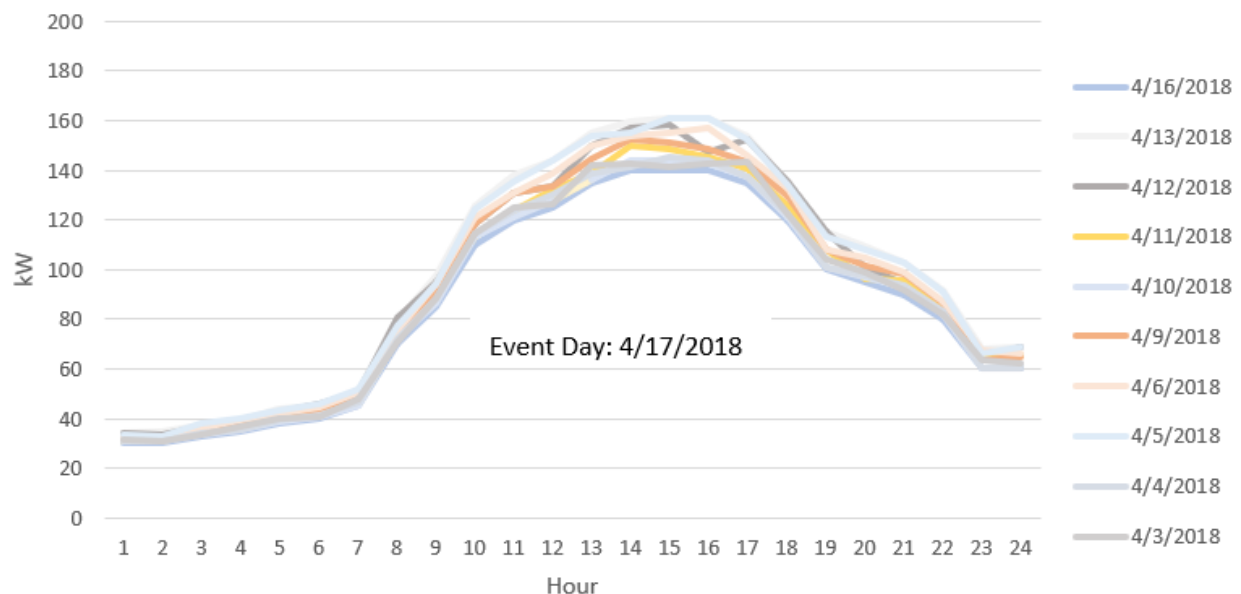


Figure 6: Identify 10 Similar Non-Event Days. Courtesy of Olivine, Inc.

2. Calculate average profile

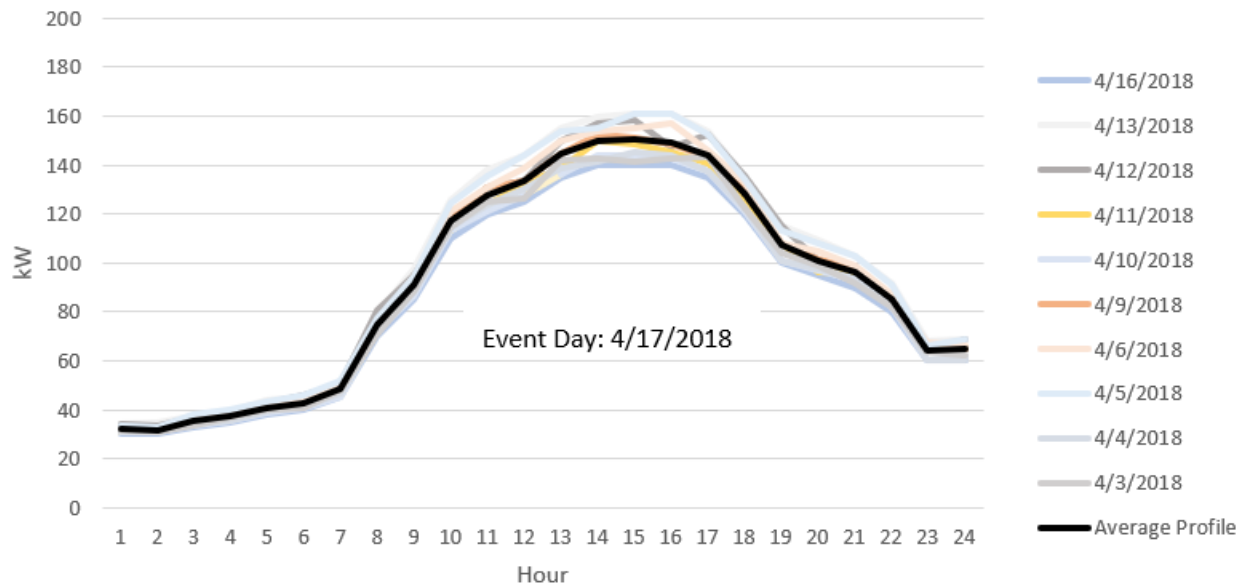


Figure 7: Calculate Average Load Profile. Courtesy of Olivine, Inc.

### 3. Determine day-of adjustment

- The day-of adjustment is based on the first three of the four hours prior to the event.
- The day-of adjustment is a multiplier that equals the ratio of the average load for these three hours on the event day to the average load for these three hours of the average profile.
- The day-of adjustment is bi-directional (i.e. may be positive or negative) and is capped at  $\pm 20\%$ .
- Note that event days with both load increase and load decrease events only utilized a single day-of adjustment. See Section 7.4.1 for additional details.

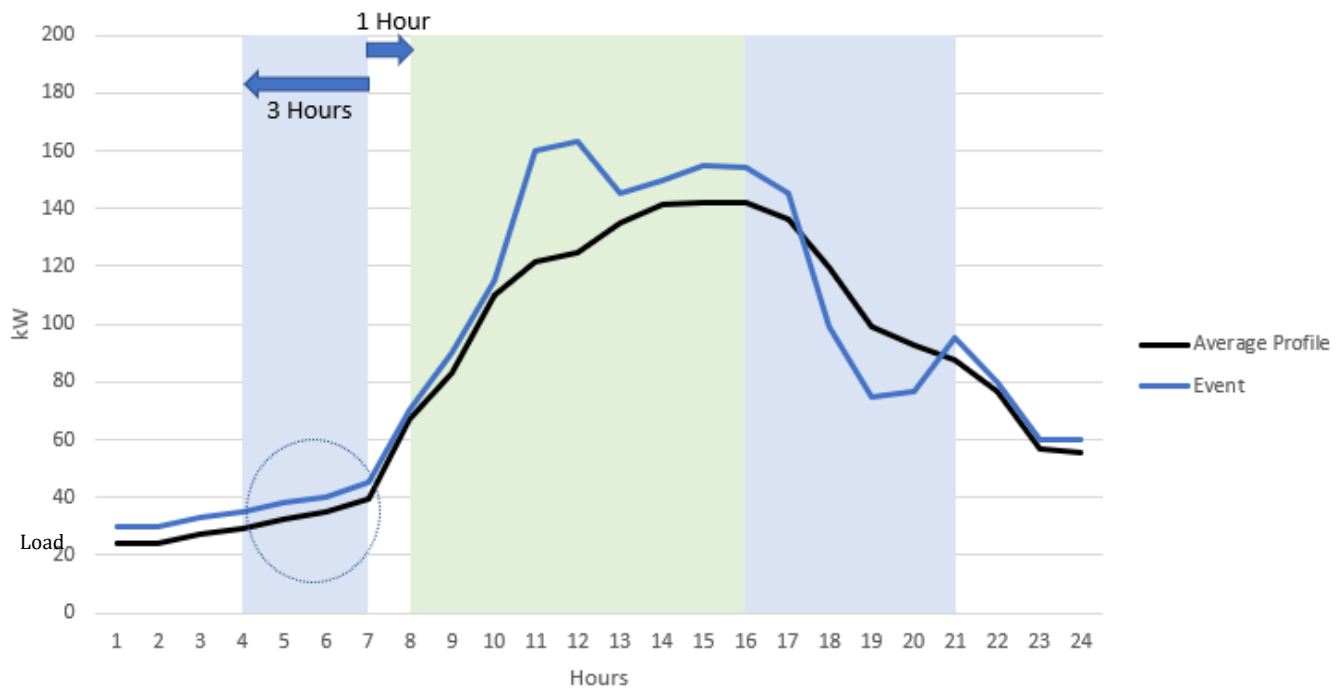


Figure 8: Determine Day-Of Adjustment. Courtesy of olivine, Inc.

4. Apply day-of adjustment to create baseline
  - The day-of adjustment multiplier is applied to the average profile for all hours of the event to produce the baseline.

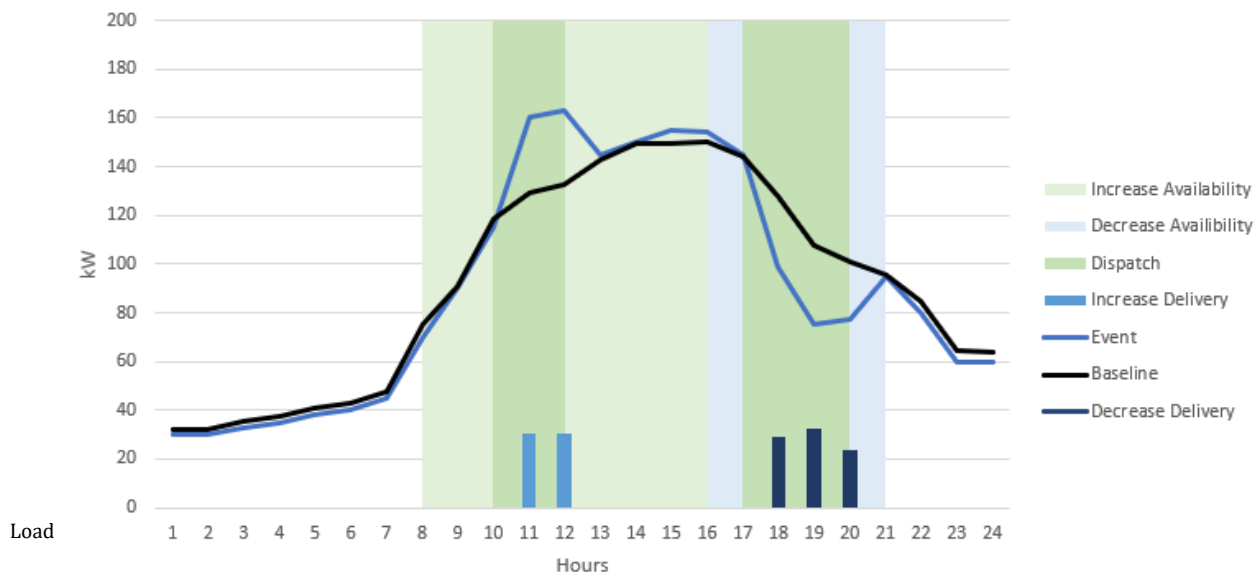


Figure 9: Apply Day-Of Adjustment to Create Baseline and Calculate Event Performance. Courtesy of Olivine, Inc.

5. Calculate the event performance

- Finally, the excess load is determined by subtracting the actual event day load from the new baseline as shown in Figure 9. Figure 9: Apply Day-Of Adjustment to Create Baseline and Calculate Event Performance. Courtesy of Olivine, Inc.
- The excess load calculated in this way is the hourly performance for the XSP. The decrease in load in the evening is calculated in the same manner.

In 2017 there were cases where the load was a positive value (net import) during the adjustment period, but the average profile used to calculate the day-of adjustment was a negative value (net export) for some hours. This poses a challenge in computing multiplicative adjustments because inherent to such factors is that there be a common floor: typically, 0 MW for load. One possible solution for this would be to set a common floor for a net exporter as the absolute possible export (e.g., -1 MW) rather than 0. In that case the absolute value (or distance) from the load or profile would be used, not the distance to 0. However, this would require that net export be explicitly allowed. Because the XSP is modelled after PDR whenever possible, and since net export is not currently allowed in PDR, choosing a negative floor is not an accepted practice. As such, no adjustment is performed in such cases in the XSP.

#### 4.3.2 Qualified Capacity (QC)

Before enrollment in the pilot is considered complete, Participants are tested for the ability to meet the 30 kW increase capacity requirement. The tested delivery relies on the hourly performance calculations as described in the previous section. The test result is computed as the average energy delivered over a two-hour period in excess of the computed baseline, identified in kilowatts. This value becomes the Load Increase Qualified Capacity (QC) for the resource. The QC is the maximum quantity that may be nominated into the pilot and is the basis for participation payments.

For participants who also elect to participate in load decrease, a separate Load Decrease QC value is determined through an additional four-hour period test to measure average energy reduction against the PDR baseline.

Note that there are no incentives associated with pre-operational qualifying tests.

#### 4.3.3 Nominations

In the XSP – as in many conventional demand response programs – a nomination is a capacity commitment made by the participant. XSP nominations are for a calendar month and can be changed monthly. For example, a participant may nominate 100 kW for a specific month with the expectation that if they are dispatched that they will be able to deliver 100 kWh per hour.

Different from conventional programs, the XSP provides flexibility in choosing availability hours. Originally these hours were open throughout most of the day, but later were refined to target hours where excess-supply is likely. As such, nominations in the XSP include a capacity quantity as well as days and times of availability using the following rules:

##### **Original XSP**

- The nominated capacity could not exceed the Qualified Capacity.



- Nominations had to include 4 hours of availability per day.
- The 4-hour requirement could be made up of either one block of 4 contiguous hours or two blocks of 2 contiguous hours
- Blocks could not span midnight
- Blocks could not overlap with 7-9 AM nor 6-8 PM
- There are 2 product options, each option containing two groupings of event days.

|          | Day Group 1       | Day Group 2       |
|----------|-------------------|-------------------|
| Option 1 | Monday – Friday   | Saturday - Sunday |
| Option 2 | Monday - Thursday | Friday – Sunday   |

*Table 2: Original XSP Nomination Day Grouping Options*

- For either option, the participant could choose to nominate availability for Group 1, Group 2, or both.
- The Participant could choose different availability hours for each day group.

Excluding the 7-9 AM and 6-8 PM periods was designed to avoid conventional peak ramping periods, noting that actual peak ramping periods can shift considerably from these conventional hours due to weather and season. The decision to keep them fixed was designed to simplify the pilot rules to ease participation.

### **Current XSP**

As a part of the addition of the load-decrease option, the load-increase hours were further constrained to better align with times that excess supply is more common. As such, the rules were updated as follows:

- The nominated capacity cannot exceed the Qualified Capacity.
- Nominations must include 5 contiguous hours of availability per day between the hours of 8 AM-4 PM
- There are 2 availability options
  - 7 Days a week
  - 5 Days a week (Weekdays)
- Optionally, load decrease availability requirements hours are 4-9PM.

Following are valid examples of nominated time periods into the XSP after the rules update:

- A participant nominates 100 kW load increase Monday through Friday: 8 AM to 1 PM,
- A participant nominates 100 kW load increase Monday through Sunday: 11 AM to 4 PM,
- A participant nominates 100 kW load increase Monday through Friday: 9 AM to 2 PM; load decrease 4 PM to 9 PM.

### **4.3.4 Base Incentive Levels and Number of Events**

Unlike conventional DR programs, it is important that the XSP have regular events to test out the ability of participants to provide excess load. As a result, XSP events are called for all participants every month, and the number of events called per month is dependent on the nomination period

selected. Given the changes in nomination options, the incentive levels varied between the original and current XSP:

### **Original XSP**

Incentives for the XSP were based on a monthly Base Participation Payment (BPP), with the BPP also dependent on the nomination period selected. Table 3 shows the relationship between the nomination period, expected number of events per month, and BPP.

| Nomination Period<br>(Available Days per Week) | Number of Available Days per Week | Base Participation Payment (\$/kW-month) | Expected Number of Events per Month |
|--|-----------------------------------|--|-------------------------------------|
| Saturday-Sunday                                | 2                                 | \$5                                      | 2 - 3                               |
| Friday-Sunday                                  | 3                                 | \$6                                      | 3 - 4                               |
| Monday-Thursday                                | 4                                 | \$7                                      | 4 - 5                               |
| Monday-Friday                                  | 5                                 | \$8                                      | 5 - 6                               |
| Monday-Sunday                                  | 7                                 | \$10                                     | 7 - 8                               |

*Table 3: Original XSP Nomination Periods and Associated BPP*

### **Current XSP**

As part of the August 2018 XSP rules update, the BPP was updated in accordance to the new nomination periods and whether the participant opts to participate in load decrease.

| Number of Available Days Per Week | Base Participation Increase Payment (\$/kW-month) | Base Participation Decrease Payment (\$/kW-month) | Expected Number of Events per Month |
|-----------------------------------|---|---|-------------------------------------|
| 5                                 | \$6   | \$2   | 8                                   |
| 7                                 | \$8   | \$2   | 8                                   |

*Table 4: Current XSP Nomination Periods and Associated BPP*

Load increase events dispatched through the pilot are either 1 or 2-hours in duration. The duration of load decrease events can range anywhere from 1 to 5-hours, depending on the participant's energy bids and market clearing prices<sup>13</sup>. Event dispatch notifications are delivered at 5 PM one day ahead.

#### **4.3.5 Participation Payment Calculation**

Participation payments are the product of the Monthly Adjusted Performance Factor (MAPF), the nomination amount, and the BPP. Calculation of the MAPF is outlined below. The payment calculation changed in the 2018 rules update as follows:

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<sup>13</sup> Note that a participant must be available for 5 hours and if awarded for all hours must respond to at least 4 hours consistent with resource adequacy rules for demand response.

### Original XSP

1. Calculate the hourly Raw Event Performance Factor (REPF). The REPF is the ratio of the performance each hour, as described in section 4.3.1, to the nomination amount.
2. Map each hourly REPF to an hourly Average Event Performance Factor (AEPF). Table 5 shows the mapping between REPF and AEPF.

| Raw Event Performance Factor | Adjusted Event Performance Factor |
|------------------------------|-----------------------------------|
| $x > 0.50$                   | 1.00                              |
| $0.25 < x \leq 0.50$         | 0.50                              |
| $0 < x \leq 0.25$            | 0.25                              |
| $x \leq 0$                   | 0                                 |

Table 5: Original XSP REPF to AEPF Mapping

3. Calculate the MAPF by averaging all the hourly AEPFs that month.

The nomination amount was then multiplied by the MAPF and the BPP to determine the participation payment for the month.

### Current XSP

As part of the XSP rules update, the payment calculation methodology was revised to more accurately reflect the participant's performance in the pilot.

A simple average of the resource's hourly raw event performance for the month is taken to determine the REPF. The hourly performance has a no zero floor, meaning load decrease during a load increase event – or vice versa – can result in a negative number that is reflected in the REPF. The REPF is then mapped to the Adjusted Total Event Performance Factor (ATEPF) in accordance to Table 6.

| Raw Event Performance Factor | Adjusted Total Event Performance Factor |
|------------------------------|---|
| $1.00 < x$                   | 1.00                                    |
| $0.20 < x \leq 1.00$         | $x$                                     |
| $x \leq 0.20$                | 0                                       |

Table 6: Current XSP REPF to ATEPF Mapping

The nomination amount was then multiplied by the ATEPF and the BPP to determine the participation payment for the month.

The incentive payment for load increase and load decrease events were calculated separately.

#### 4.3.6 Joint XSP / SSP II Participation Option

Prior to the introduction of load decrease in the XSP in August 2018, participants could enroll in both the XSP and the SSP II. In that case, the following additional requirements also applied:

- The XSP and SSP II resources must be composed of the identical set of customer locations.

- The SSP II resource may not bid within 4 hours of the XSP resource nomination periods. For example, if the nomination period for the XSP is 8 PM – 12 PM, then the SSP II bids cannot be later than the hour ending at 4 PM. This is to ensure there is no impact on baseline calculations from events on either pilot to the other.

There were no participants that had resources enrolled in both pilots simultaneously in 2015, 2016, or most of 2017. The first joint participation occurred in late 2017 when one of the XSP participants enrolled its XSP resource in the SSP II (enrollment completed in December 2017 with participation beginning in 2018). This joint resource participated in both the XSP and SSP II simultaneously starting in 2018 until the introduction of the new XSP rules, which eliminated joint participation. This participant did ultimately remain in the XSP and elect to also respond to load decrease dispatches.

### 4.3.7 Demand Charge Mitigation

As discussed previously, due to high interest from large non-residential customers, even though these customers were on retail rates that included demand charges, pilot eligibility was expanded to include these customer classes. As a result, all customers that participated in the XSP were on retail electric rates that included TOU demand charges. While most participants were able to mitigate the impact of pilot participation on their TOU demand charges through their nomination behavior, some did incur additional TOU demand charges due to responding to XSP events. Those participants that did incur additional TOU demand charges were eligible for an additional pilot payment (referred to as a Demand Charge Offset payment) to offset a portion of these incrementally incurred demand charges. Such an offset was added to the base Pilot participation payment and was not a reduction in the retail billed demand charges.

The justification for implementing this additional adjustment is that the current retail TOU periods do not align with the periods of highest and lowest wholesale market prices, resulting in low wholesale prices occurring in the middle of the day during retail Peak and Part-Peak TOU periods. As retail TOU periods are shifted to later in the day over the next several years, these retail periods should better align with wholesale market peaks, reducing the conflicting signals created by asking a participant to increase load due to excess supply in the wholesale market during a retail peak TOU period. As a result, the Demand Charge Offset is a temporary solution that has been implemented exclusively for the pilot and is not meant to be a long-term solution or applied outside of the XSP. In addition, while the Demand Charge Offset is used to offset all or part of the incremental TOU demand charges, monthly maximum demand charges were excluded from this calculation. Monthly maximum demand charges are excluded because even when retail TOU periods are better aligned with wholesale price trends, monthly maximum demand charges, which are independent of TOU periods, will not change.

For unbundled customers, the demand charge offset excluded the generation portion of the demand charge rate. This is because unbundled customers receive a Generation Credit from PG&E which credits them back all generation related demand and energy charges.

To calculate the demand charge offset, the amount of increased demand charge that is attributable to XSP events must be determined. To do this, the underlying customer was required to provide to Olivine the retail customer bill and device-level sub-metered data for the specific asset or assets

used to respond to the XSP events<sup>14</sup>. Olivine then performed the following steps to compute the demand charge offset:

1. For each event day, perform a 10-in-10 baseline calculation on the sub-metered data. This will not include a day-of adjustment.
2. Calculate the per-event sub-metered performance data.
3. Subtract the per-event sub-metered baseline data from the whole-premises meter data.
4. Calculate what the TOU demand charges would have been if not for the XSP events.
5. Subtract the actual demand charges taken from the customer bill from the calculated demand charges.
6. Cap this value at the participation payment. For example, if the payment is \$10/kW-month and the nomination is for 1 MW, then the demand charge offset cannot exceed \$10,000. Any incurred demand charges more than what is covered by the XSP are the responsibility of the participant.

### Example

Below is an example of how this process is performed. For simplicity, the example makes the following assumptions:

- There is only one event for the month,
  - All demand charges are set on the same day as the event,
  - The month is during the SUMMER season,
  - The customer is on the E-19P rate,
  - The customer nominated a load increase amount of 100 kW with an availability of 7 days per week.
1. For each event day, perform a 10-in-10 baseline calculation on the sub-metered data.

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<sup>14</sup> The types of assets that can be sub-metered include batteries, PV systems, EV chargers, chillers, and pumps.

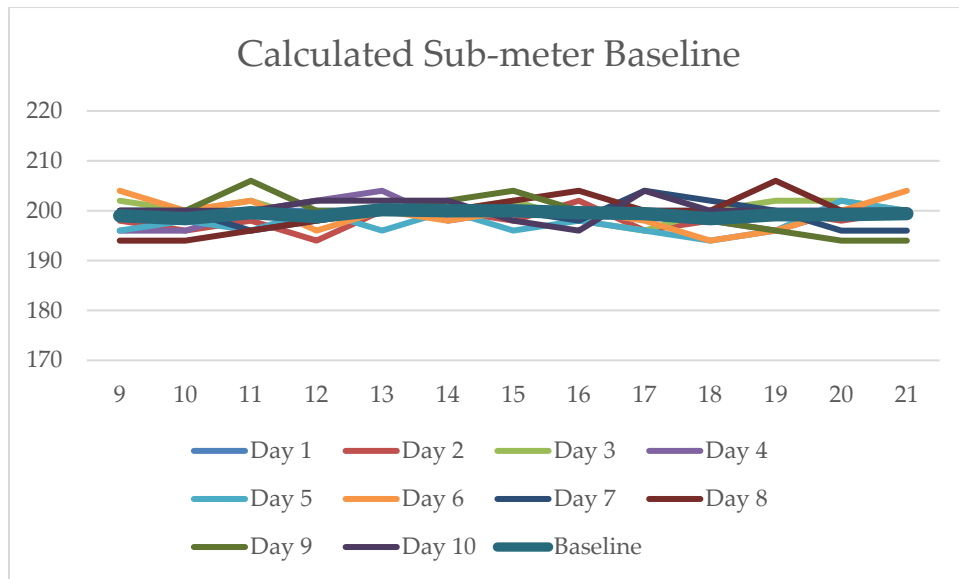


Figure 10: Demand Charge Mitigation: 10 Similar Non-Event Days

The 10-in-10 baseline is calculated using a similar procedure to how it is calculated for incentive payments, except sub-meter data is used instead of whole-premise meter data and no day-of adjustment is applied.

2. Calculate the per-event sub-metered performance data.

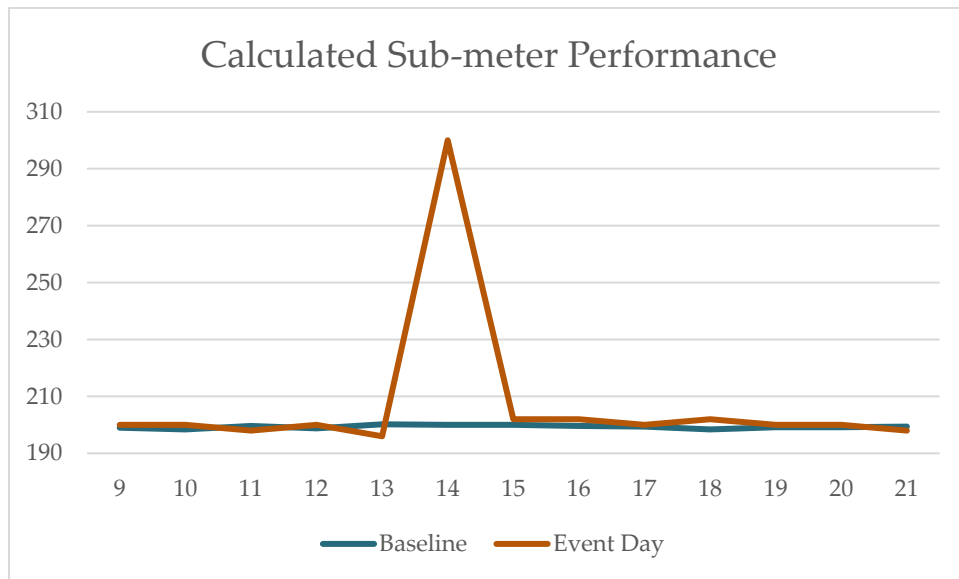


Figure 11: Demand Charge Mitigation: Calculate Sub-Metered Performance

In this example, the load increase event was a one-hour event from 2 PM – 3 PM. The load increase, using sub-metered data was calculated to be 100 kW (the difference between the measured 300 kW load and the calculated baseline of 200 kW load).

3. Subtract the per-event sub-metered performance data from the whole-premises meter data.

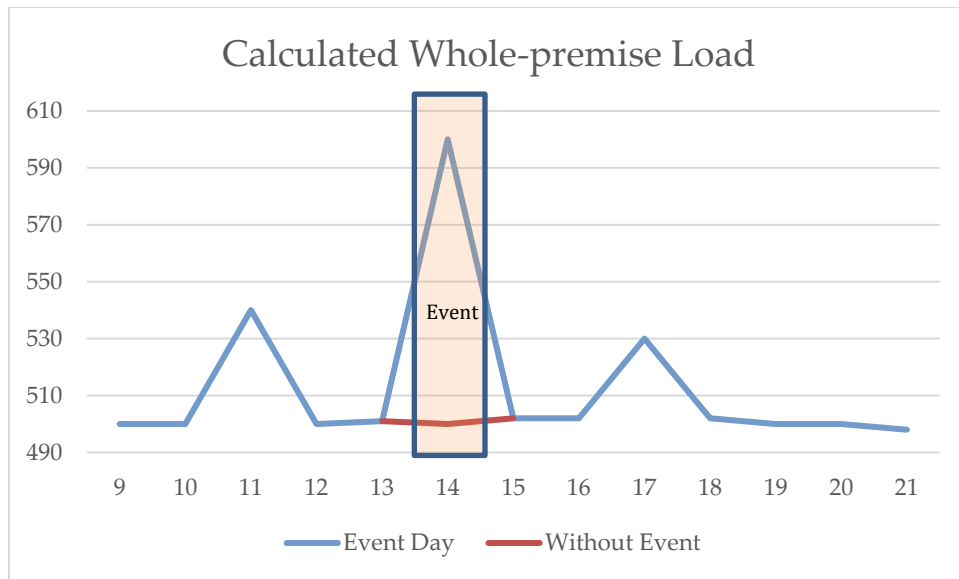


Figure 12: Demand Charge Mitigation: Whole-Premise Load

In this example, the calculated event contribution (red line) is subtracted from the whole-premise load on the event day (blue line).

4. Calculate what the TOU demand charges would have been if not for the XSP events.

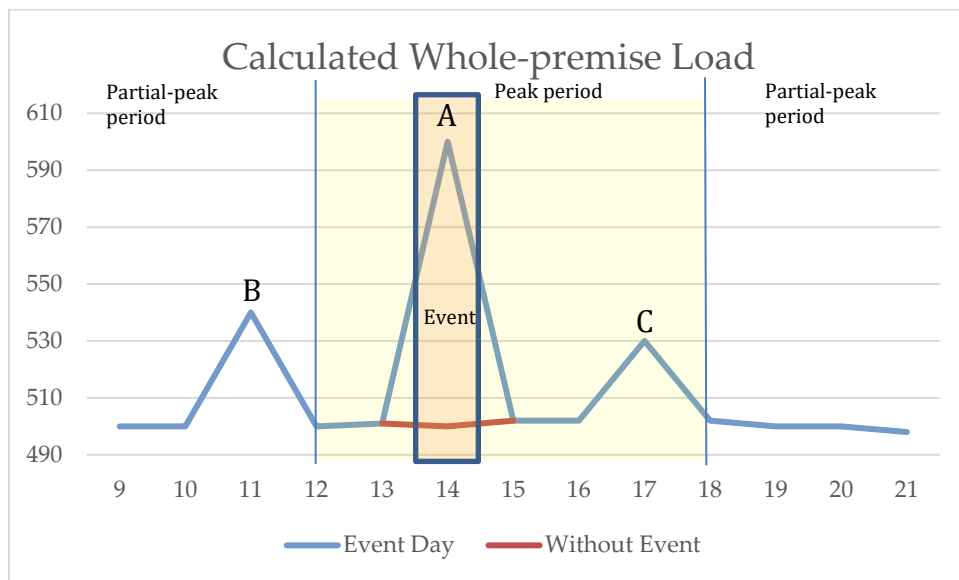


Figure 13: Demand Charge Mitigation: Calculate Contribution of Event to Demand Charge

These TOU demand charges are the Maximum Peak Demand Summer, Maximum Part Peak Demand Summer, and Maximum Part-Peak Demand Winter demand charges. As mentioned above, because the Demand Charge Offset is only meant to be a short-term solution until retail TOU periods are adjusted, and changes to the retail TOU periods will not impact the monthly maximum demand charges, this calculation the Demand Charge Offset does not compensate for

any incremental monthly maximum demand charges (Maximum Demand Summer or Maximum Demand Winter) incurred due to responding to any XSP events.

In this example, had there not been an XSP event, the maximum peak-period demand would have been 530 kW (peak C) and the maximum partial-peak demand would have been 540 kW (peak B). For a customer on the E-19P rate, the demand charges would therefore be,

| Period                          | Demand Charge Rate (\$/kW) | Maximum Demand (kW) | Demand Charge (\$) |
|---------------------------------|----------------------------|---------------------|--------------------|
| Maximum Peak Demand Summer      | 16.60                      | 530                 | 8,798.00           |
| Maximum Part-Peak Demand Summer | 4.53                       | 540                 | 2,446.20           |
| Total TOU Demand Charges (\$)   |                            |                     | 11,244.20          |

*Table 7: Demand Charge Mitigation: Example Demand Charge Calculation 1*

5. Subtract the actual demand charges taken from the customer bill from the calculated demand charges.

Due to the XSP event (peak A) the actual maximum peak demand charge is 600 kW. There is no change to the maximum part-peak demand. Therefore, the actual TOU demand charges on the customer bill would be,

| Period                          | Demand Charge Rate (\$/kW) | Maximum Demand (kW) | Demand Charge (\$) |
|---------------------------------|----------------------------|---------------------|--------------------|
| Maximum Peak Demand Summer      | 16.60                      | 600                 | 9,960.00           |
| Maximum Part-Peak Demand Summer | 4.53                       | 540                 | 2,446.20           |
| Total TOU Demand Charges (\$)   |                            |                     | 12,406.20          |

*Table 8: Demand Charge Mitigation: Example Demand Charge Calculation 2*

The difference between the actual demand charge and the calculated demand charges without XSP is  $\$12,406.20 - \$11,244.20 = \$1,162.00$ .

6. Cap the Demand Charge Offset at the participation payment.

Since the customer had a nominated load increase of 100 kW with an availability of 7 days per week, the maximum monthly participation payment would be  $\$10 / \text{kW} \times 100 \text{ kW} = \$1,000$ .



Therefore, though the Demand Charge Offset was calculated to be \$1,162.00, it would be capped at \$1,000.00.

#### 4.4 XSP – Electric Vehicle Charge Network Rules

An option of PG&E’s Electric Vehicle Charge Network (EVCN) program required participation in the XSP in order to leverage the operational knowledge and processes that the XSP already has in place. In addition, EVCN participation enables the XSP to incorporate a technology type (electric vehicles) and customer classes (smaller commercial and multi-unit residential) into the pilot which have been absent thus far. Customers who choose to implement custom pricing at their site, such as free charging or a flat fee, were required to participate in the EVCN Load Management Plan. As intended, much of the rules and requirements for participation were drawn from the standard XSP with slight variations.

##### 4.4.1 Participants

The roles in this variant are different from the standard XSP in that the electric vehicle service provider (EVSP) acts as the participant in the pilot, while the customer – also identified as the *site host* – is the recipient of benefits and directly receives the incentive payments via an on-bill credit.

##### 4.4.2 XSP Baseline and Performance Methodology

The performance calculation also utilized the “10-in-10” baseline calculation with the exception that the day-of adjustment was set to zero with the rationale that EVSE usage is highly variable, thus the day-of adjustment would have introduced more uncertainty.

##### 4.4.3 Qualified Capacity & Nominations

Among the differences are the nomination options available to EVSPs. Instead of performing a QC test to determine the QC, the QC is set administratively by taking the product of the number of EVSE on the site and their respective nameplate maximum charge rating. This QC in turn was set as the fixed capacity nomination.

The availability hours were also more stringent with mandatory load increase availability for 5 contiguous hours between 8 AM to 1 PM and mandatory load decrease availability for 5 contiguous hours between 4 PM to 9PM, 7 days per week.

##### 4.4.4 Base Incentive Levels

Given the fixed availability hours, the BPP is set for \$5/kW-month for load increase and \$5/kW-month for load decrease, thus the participant can potentially earn up to \$10/kW-month. Note that this incentive appears as a bill credit on the customer’s retail electricity bill.

A simple average of the resource’s hourly raw event performance for the month is taken to determine the REPF. The hourly performance has a no zero floor, meaning load decrease during a load increase event – or vice versa – can result in a negative number that is reflected in the REPF. The REPF is then mapped to the Adjusted Total Event Performance Factor (ATEPF) in accordance with Table 9.

| Raw Event<br>Performance Factor | Adjusted Total<br>Event Performance<br>Factor |
|---------------------------------|---|
| $1.00 < x$                      | 1.00  |
| $0.20 < x \leq 1.00$            | x   |
| $x \leq 0.20$                   | 0   |

*Table 9: EVCN Adjusted Performance*

The nomination amount is then multiplied by the ATEPF and the BPP to determine the participation payment for the month.

## 5 Pilot Operations

### 5.1 Recruitment and Enrollment

The first step in recruiting participants into the pilot was to perform a marketing outreach effort to as many appropriate entities as possible.

A list of 32 possible organizations and their contacts was drafted using participation lists from previous pilots and other PG&E programs, including SSP prospective participants, as well as additional PG&E and Olivine contacts. The contacts on the list were invited to the kickoff meeting, both via email and phone. While the XSP had been introduced at earlier SSP meetings, it was on December 16, 2015, that an XSP-focused kick off meeting was held at the PG&E Pacific Energy Center with many participating by phone. This meeting included specific participation rules, enrollment steps and materials were outlined for prospective participants.

#### 5.1.1 Enrollment Process

Potential participants filled out a declaration of interest (DOI) and provided detailed information on customer locations and excess supply amounts. In the case that the participant was not a direct customer, the participant also provided customer-executed agreements authorizing PG&E to release customer data to the participant. These forms, called customer information service-request forms (CISRs), also acknowledged that the customer was interested in enrolling in the pilot.

Once submitted, Olivine reviewed the enrollment materials and submitted them to PG&E for final review. PG&E proceeded with manual validation of the CISRs and checked eligibility of customers for enrollment, including identifying Sub-LAP and LSE membership. Ultimately the participant would acknowledge the enrollment of the eligible customers with the intention of placing them into a single PDR for participation, or in the case of the 30-kW option, a simulated PDR.

Following the enrollment, the participant signed a participation agreement with Olivine. Two training sessions were held: one on the rules, requirements and process of the pilot, and one on using the Olivine DER system to place bids and manage the participant's resource. A qualified capacity test was then arranged to ensure the participant could meet the minimum curtailment requirements. Potential participants started out by providing Olivine with a declaration of interest.

#### 5.1.2 Enrollment Details

From this original list of 32 organizations, 8 distinct organizations attended the meeting in addition to PG&E and Olivine staff:

- EnergyHub
- SolarCity
- Comverge
- Earth Networks dba WeatherBug Home (now Whisker Labs)
- ENGIE Storage (formerly Green Charge Networks (GCN))

- Stem
- Electric Motor Werks
- Johnson Controls

In addition, Green Lots and Marin Clean Energy, a CCA, showed interest in the pilot after this kickoff meeting<sup>15</sup>.

Of these 10 organizations, 4 submitted a declaration of interest:

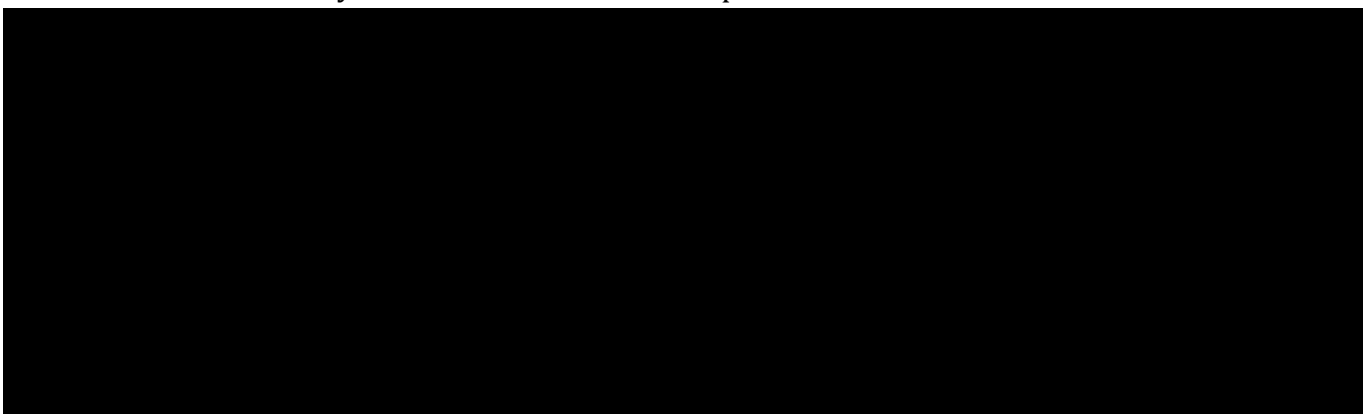
- [REDACTED]
- [REDACTED]
- [REDACTED]
- [REDACTED]

Of these 4 organizations, one participant, [REDACTED], fully enrolled in the pilot.

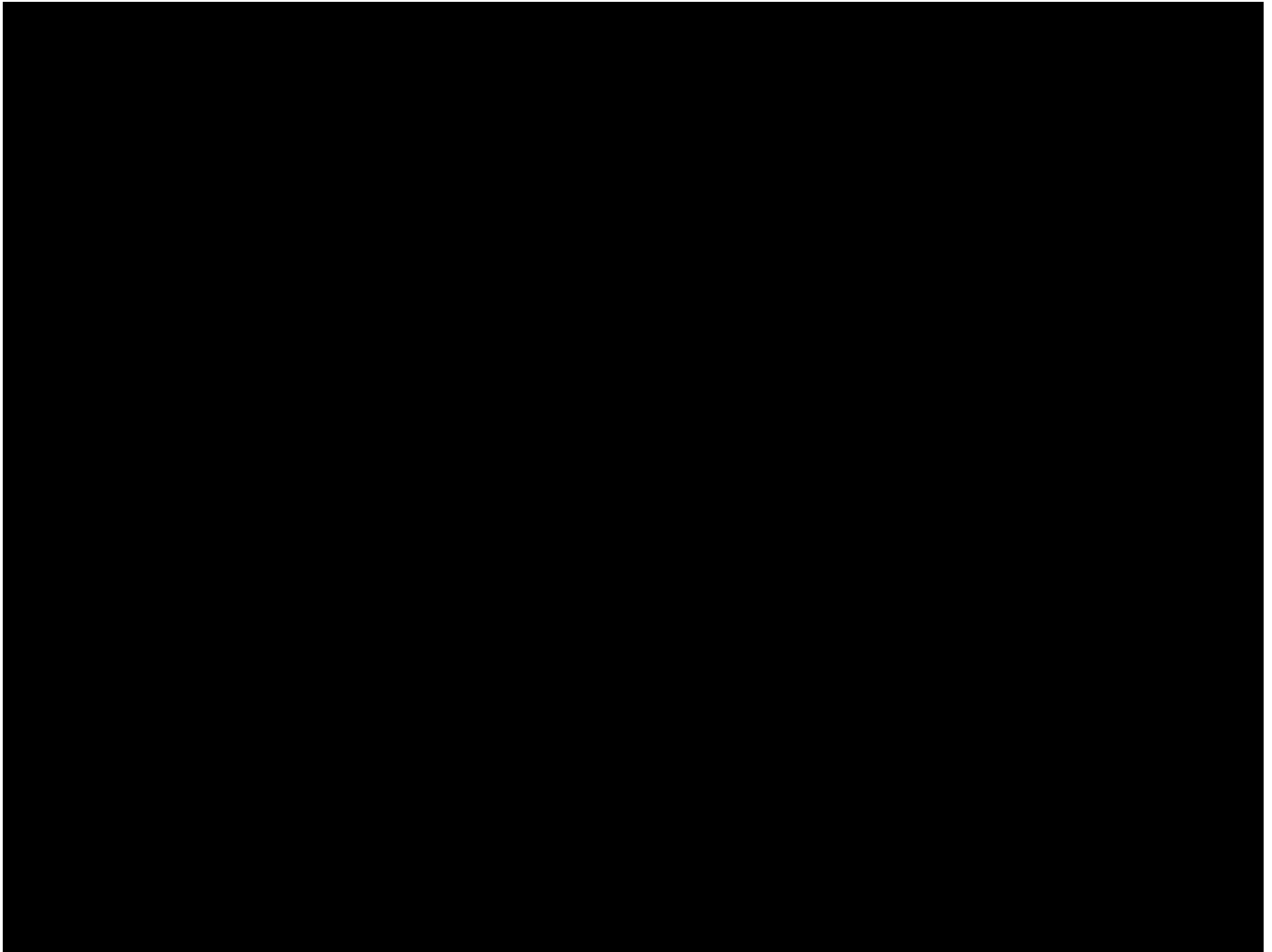
There were varying reasons as to why some of the sites or entities could not participate in the pilot, including the following:

- Some had no actual customers, or no customers suitable for providing excess load.
- Some were in the business of reducing demand charges for their customer(s) and therefore felt the XSP would not be cost effective considering that it could increase demand charges.
- Some were dependent on other funding sources (e.g. the Self Generation Incentive Program (SGIP)) to enable them to deploy the technology at customer sites. When these funding sources were not procured, the participants were not able to proceed with deployment of the controls and systems at customer sites that could support the XSP.
- Some were focused on delivering to the SSP II or to the California-wide Demand Response Auction Mechanism (DRAM) and either did not have the company bandwidth to support XSP or did not have enough customers to support both activities.

In 2017, due in large part to the addition of the TOU demand charge mitigation feature of the pilot, multiple parties went through all or part of the enrollment process. Table 10 lists these parties and summarizes how far they reached in the enrollment process.



<sup>15</sup> Note that other parties provided declarations of interest for 2017 participation but are not counted here.



*Table 10: Parties That Went Through All or Part of the XSP Enrollment Process*

Details of the participating resources are discussed in the next section.

### **5.1.3 Enrolled Participants**

Table 11 summarizes the amount of reduction and the sources used to deliver these reductions by participant.

*Table 11: Participant Qualified Capacities and End-Use Technology*

\*Signifies a change to QC value in 2018

## 5.2 Event Dispatch Trigger

Events in the XSP were initially set administratively as it was critical that the XSP have regular events to test out the ability of participants to provide excess load. In May 2018, the XSP began using day-ahead oversupply forecasts from PG&E's Short-Term Electric Supply (STES) group as a way of triggering dispatches.

STES originally created a day-ahead forecast of renewable generation and "net load" (the portion of customer load not served by renewables) as an internal indicator of the likelihood of oversupply events, during which NP15 prices may become negative for multiple real-time intervals and system reliability may be challenged by a supply-demand imbalance due to excess fixed generation on the grid.

STES then repurposed its oversupply indicator forecast to provide an hourly forecast of both the average percentage of customer load served by renewables and the likelihood of negative NP15 prices in the real-time wholesale market. The information included in this forecast was,

- The date for which the report was generated (usually the following day),
- Operation hour of the corresponding date,
- Percent of cleared PG&E wind energy in the day-ahead market to PG&E forecasted bundled load,
- Percent of cleared PG&E solar energy in the day-ahead market to PG&E forecasted bundled load,
- Percent of cleared PG&E biomass, biogas, geothermal, small hydro, FIT (excluding solar), green imports from interties and virtual supply awards to PG&E forecasted bundled load,
- Percent of cleared PG&E large hydro energy in the day-ahead market to PG&E's forecasted bundled load,
- Sum of Wind, Solar, RPS and Large Hydro Share percentages,
- Non-renewable percentage of PG&E forecasted bundled load,

- Likelihood of observing negative real-time NP15 prices at operating hour of the corresponding date conditioned on the forecasted net load. This conditional likelihood is estimated from the historical real-time NP15 prices and the actual net load values.

The XSP started utilizing this daily forecast of oversupply periods to determine when to call events. The trigger for a dispatch was initially set to hours where the probability of oversupply was 50% or greater. If there were more than two intervals which met the trigger, the hour(s) with the highest probability were selected. Throughout the rest of 2018, the trigger was adjusted multiple times within the range of 30-50% probability of oversupply to ensure that dispatches were routine and that the total number of events and event hours for the month were close to the targets.

Initially, STES would create the day-ahead forecast after results of the day-ahead wholesale market were posted. However, because the day-ahead wholesale market was occasionally late in posting market results, results from the STES modeling would sometimes not be completed in time for the XSP notification deadline. As a result, starting in August 2018, STES also ran the model in the morning prior to the close of the day-ahead wholesale market. This morning run would not include results of the day-ahead market but did guarantee that there was a day-ahead forecast that could be used. On days when the post-day-ahead market run could be completed in-time to meet the XSP notification deadline, the post-market run values were used instead.

### 5.3 Example Events

The following figures show example event dispatches under the XSP.

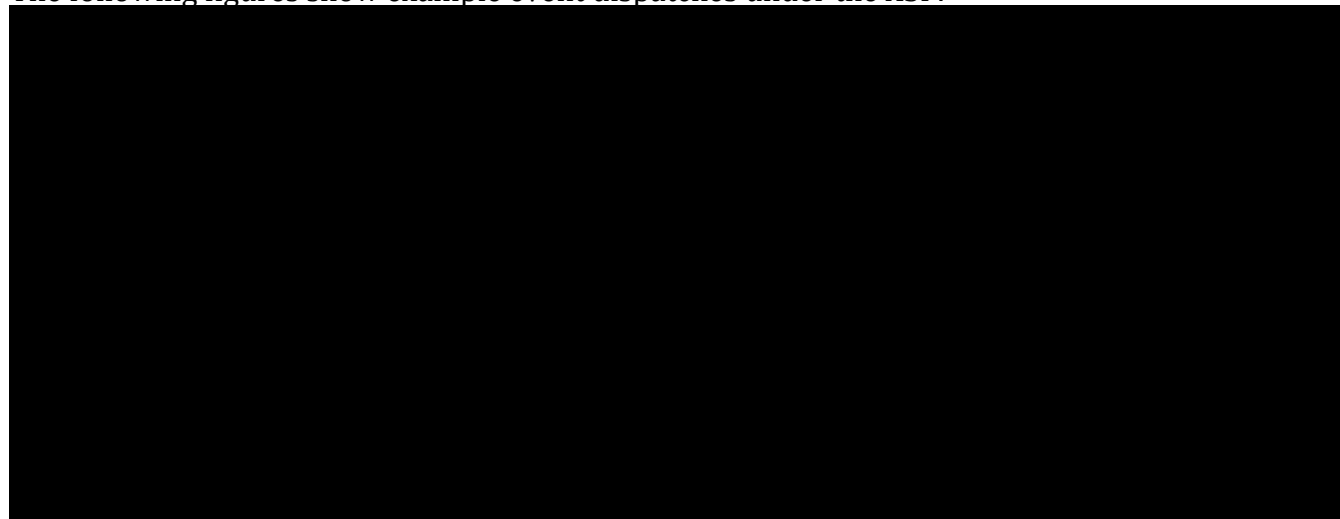


Figure 14: Load and Baseline Profiles for [REDACTED]

Figure 14 shows the measured load and calculated baseline along with the [REDACTED] site from [REDACTED]. The light blue line identifies the baseline calculated per the rules as defined in Section 4.3.1. The dark blue line identifies the target increase to achieve the [REDACTED] nomination. Finally, the green line identifies the actual load

during that time, noting that in this case the load is greater than the target indicating successful delivery of the requirement.

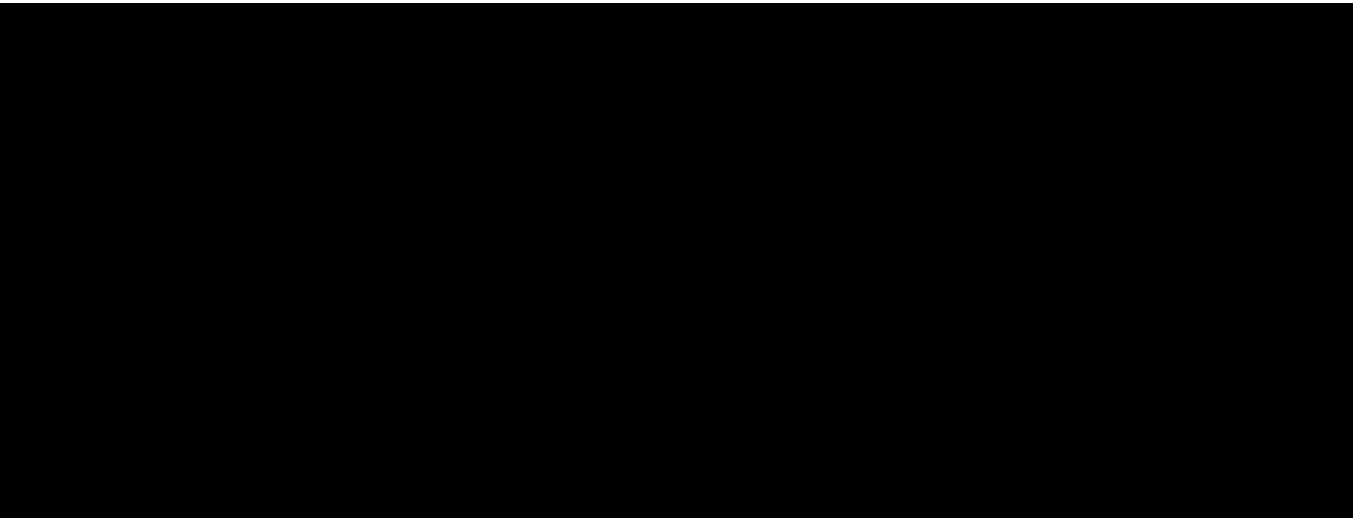


Figure 15: Load and Baseline Profiles for [REDACTED]

Figure 15 shows the measured loads and calculated baselines for a [REDACTED]. The light blue line identifies the baseline calculated per the rules as defined in Section 4.3.1. The dark blue line identifies the target increase to achieve; in this case a [REDACTED] increase nomination and a [REDACTED] decrease award. Finally, the green line identifies the actual load during that time. In the case of the load increase event, [REDACTED]. Similarly [REDACTED].

5.4 Resource Operations

[REDACTED]

[REDACTED] The summary of 2016 and 2017 performance can be seen in Appendix D. [REDACTED]

Because the adjusted performance is capped at 100% and measured on an hourly basis, any under-performing hour will reduce the average adjusted performance value. Section 4.3.5 details the difference between raw and adjusted performance.



[Redacted Table Content]

Table 12: [Redacted]

\* Signifies no nomination during this period.

[Redacted Table Content]

Table 13: [Redacted]

From Table 12 and Table 13, the [Redacted]  
[Redacted]  
[Redacted]  
[Redacted]

[Redacted] Because the Adjusted Performance is capped at 100% and measured on an hourly basis, any under-performing hour will reduce the average Adjusted Performance value. Section 4.3.5 details the difference between raw and adjusted performance.

[Redacted]  
[Redacted]  
[Redacted]  
[Redacted]

[Redacted]  
[Redacted]  
[Redacted]  
[Redacted]  
[Redacted]

[REDACTED]

[REDACTED]

[REDACTED] Table 14 shows the performance of the resource throughout the pilot participation. [REDACTED]

[REDACTED]

[REDACTED] The summary of 2017 performance can be seen in Appendix D.

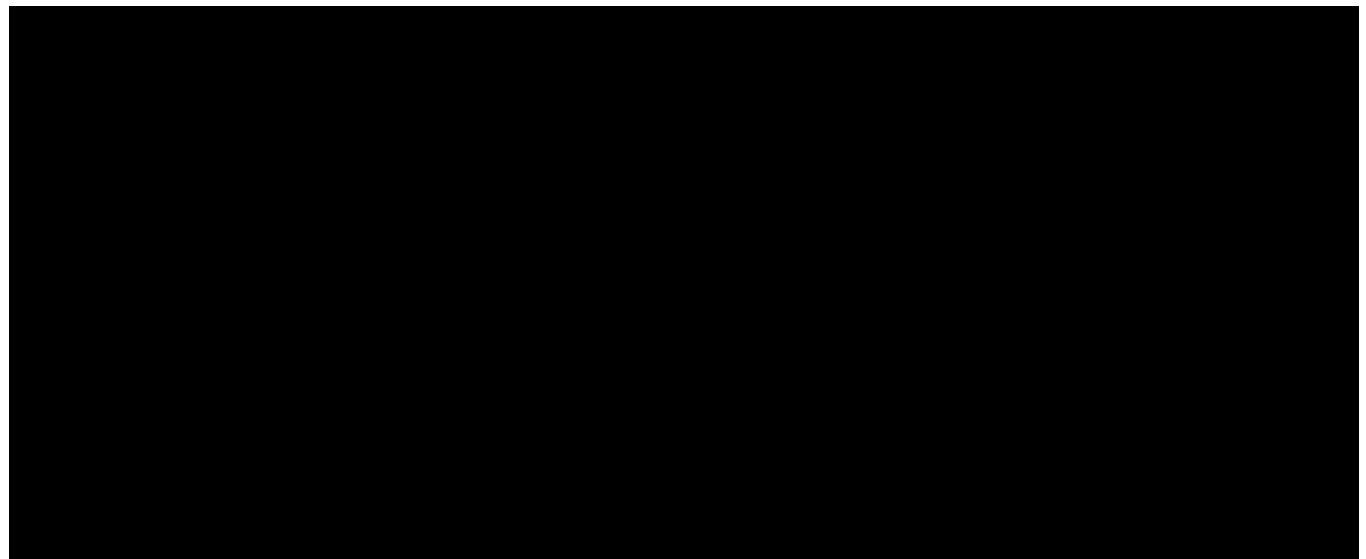


Table 14: [REDACTED]

[REDACTED]

[REDACTED]. Table 15 shows the performance of the resource throughout the pilot participation.

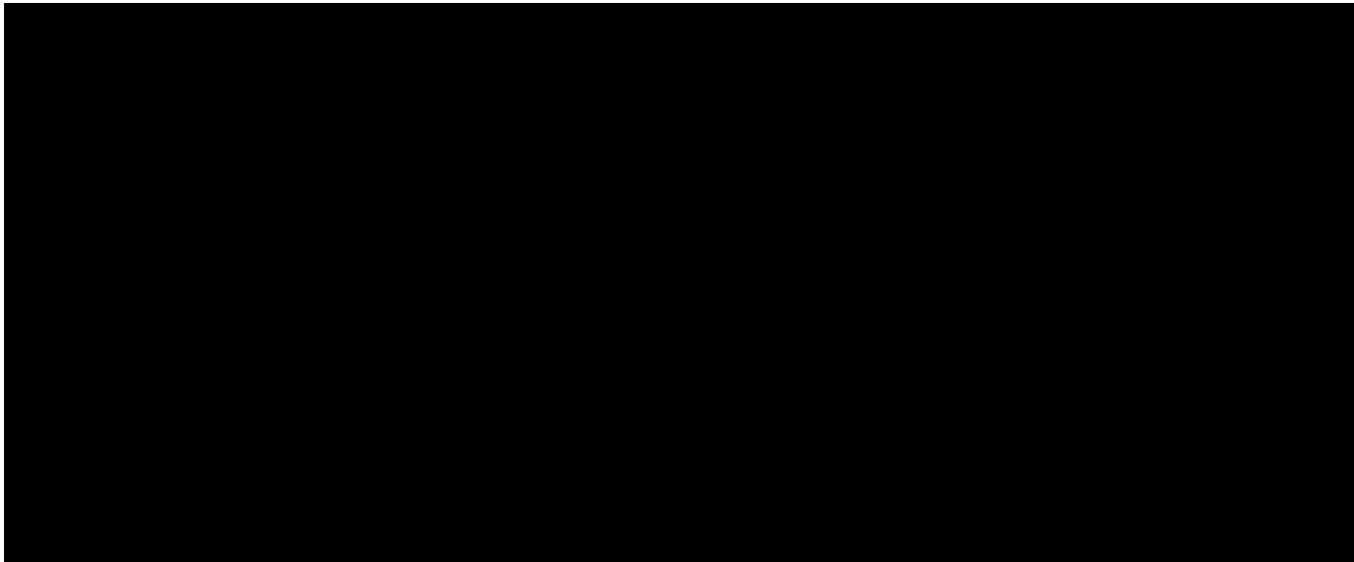








Table 15: 



  
 Table 16 shows the performance of the  
resource throughout the Pilot participation.   
  
  


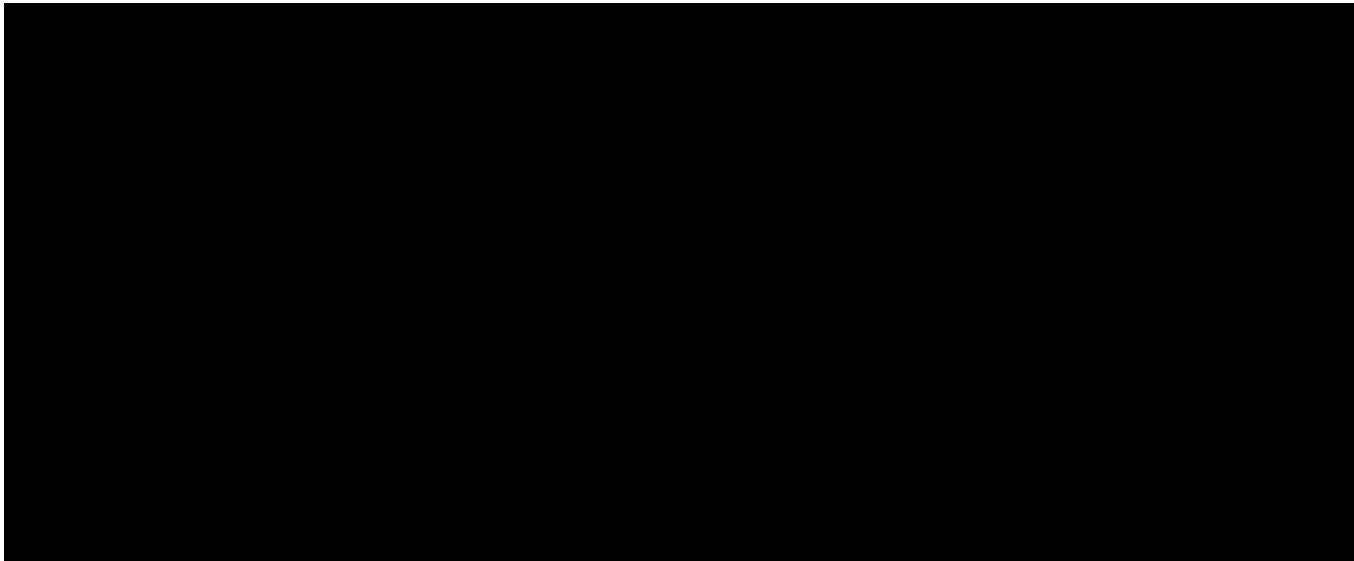
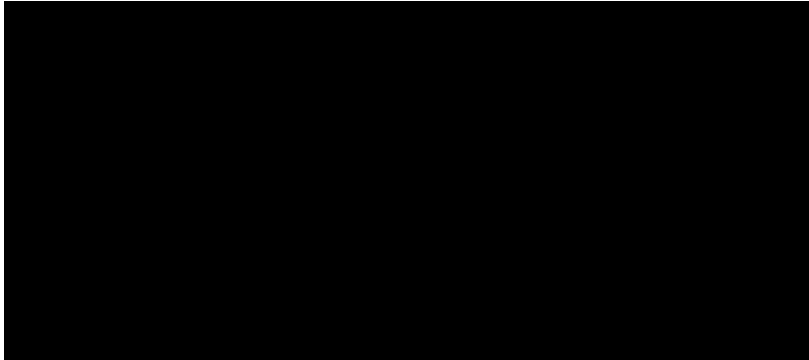


Table 16: 

## 5.5 Value of Participation

Each participant received participation incentives for each month they nominated. Table 17 summarizes incentive payments received by each resource based on its participation. Appendix B lists the monthly breakdown of incentive payments for each resource.

A large black rectangular box redacting the content of Table 17.

*Table 17: Total Payments to Participants, 2018*

## 6 Lessons Learned

This section outlines the lessons learned throughout implementation of the XSP. The lessons learned are categorized into enrollment, demand charge mitigation, value to participants, and operational feasibility.

### 6.1 Enrollment

There was initially much interest from parties to learn about the XSP, though not as much follow through as one might hope. This can be attributed to several factors:

- Some prospects engaging in early pilot discussions genuinely do not know if their company and/or customers are a good match for such pilots or are very early stage. As such, a common theme is a declaration of interest but ultimately with no actual customers to enroll.
- Other prospects engaging in such discussions are tasked with keeping abreast of market activities and/or gaining competitive intelligence and may have no actual interest in participation.
- Some prospective participants were dependent on additional funding mechanisms (e.g. SGIP) to help them fund enrollment of customer deployments into their own energy management service offerings. While these parties expressed interest in the XSP, they ultimately did not receive the additional funding, resulting in the prospective participants not being able to deploy their technology at the customer sites.
- While the DRAM is a demand reduction opportunity, the high visibility of that pilot created either an alternative for some prospects, or at least an alternative for evaluation. This had the effect of forestalling prospects because of their belief that they would get a DRAM contract, or for those who were awarded a contract, forestalling XSP participation while fulfilling the DRAM.
- Some prospective participants were concerned with the limited duration of the XSP and the risk that the pilot might not be extended beyond 2017. As a result, they felt that the investment in time and equipment needed to qualify for and participate in the pilot was not worth the potentially short duration, particularly when weighted against participating in other DR programs. Though approval to continue the XSP beyond 2017 was not granted until December 2017, and throughout the year PG&E and Olivine were very clear with parties that there were no guarantee that the XSP would be approved beyond 2017 prior to Commission approval, some prospective participants felt as the year progressed that the chance of approval to continue the pilot into 2018 was reasonable enough (and the potential short-term benefits were large enough) to take a chance on enrolling prior to a final decision from the Commission.

Since enrollment in the XSP was very low in 2016, various changes to the XSP were discussed and implemented for 2017 to increase enrollment, including:

- Implementation of a Demand Charge Offset as an additional component of the XSP participation payment to cover at least a portion of any calculated increase in TOU demand

charges due to responding to XSP events. This additional payment is meant to compensate for the fact that current retail TOU periods do not align with wholesale market trends, resulting in XSP participants potentially being asked to increase load due to excess supply or low wholesale market prices during the peak retail TOU period. However, as retail TOU periods are shifted to later in the day in the future, these retail periods should better align with wholesale market peaks, reducing the potential of a participant incurring additional peak TOU demand charges due to responding to an XSP event. As a result, this additional payment is a temporary solution that has been implemented exclusively for the pilot and is not meant to be a long-term solution or applied outside of the XSP. In addition, monthly maximum demand charges are excluded from the Demand Charge Offset because even when retail TOU periods are better aligned with wholesale price trends, monthly maximum demand charges, which are independent of TOU periods, will not change.

- Updated marketing materials on eligibility and the value of the XSP to the participant as well as the grid.
- An outbound email campaign to all participants of SSP II and XSP, plus any other known contacts provided by PG&E, utilizing these new materials and describing these new rules.

In general, larger commercial customers, and 3<sup>rd</sup> parties aggregating larger commercial customers, were more interested in participating in the XSP than small commercial and residential customers, particularly after implementation of the TOU demand charge offset.

## 6.2 Mitigating Demand Charges Through Bidding Behavior

An additional issue for some parties was the risk of increased demand charges due to responding to XSP events. Some analysis performed by Olivine and PG&E has shown that the increased demand charges for larger commercial customers can easily exceed the potential participation payments for any individual customer. Customers can avoid this impact by selecting a pilot availability period that is not coincident with their monthly peak demand or peak demand for any of the TOU periods (e.g. peak and part-peak) so that responding to an XSP event will not set a new monthly peak or TOU peak demands. Additional methods of mitigating the impact of pilot participation on demand charges include avoiding shifting load from a lower TOU demand charge period to a higher TOU period (e.g. shifting load from partial peak to peak) or avoiding the highest TOU demand charge periods altogether.

However, even though it was possible for a customer to mitigate or even eliminate any impact on demand charges, many prospective participants subject to demand charges felt they would either not be able to utilize the above methods or there was too much risk. Implementation of the Demand Charge Offset acted as a “safety net” and reduced the concern of incurring additional TOU demand charges enough to convince multiple larger commercial participants to enroll in the pilot. In addition, through the pilot we have learned that many participants that were concerned about incurring additional demand charges have been able to mitigate the risk of additional TOU demand charges in their bidding behavior, which alleviated the concern of a negative impact from demand charges.

## 6.3 Value to Participants

Participants received up to \$10/kW-month year-round for participating in the pilot, with details of the monthly payments for each participant included in Section 5.5 and Appendix B. This compares favorably to other DR programs. As discussed in the previous section, this incentive payment could easily be dwarfed by increased demand charges which can exceed \$20/kW-month during the peak months and periods. Figuring the interdependency between DR program incentive levels and impact of DR participation on retail bills will be instrumental for enrollment in the XSP of customers with the most potential (i.e., larger commercial) to help realign supply and demand.

## 6.4 Operational Feasibility

### 6.4.1 Baselines

The pilot was successful in calculating performance based on an inverse CAISO 10-in-10 baseline methodology for load increase events. As outlined in Section 5.3.1, load decrease events also utilize the CAISO 10-in-10 baseline methodology. For event days where there are both load increase and decrease dispatches, the later decrease event utilizes the same day-of adjustment from the afternoon increase event. This was implemented to avoid potential overlap between the afternoon event hours and the evening hour adjustment hours. For example, a 12 PM – 1PM load increase event and a 4 PM – 6 PM load decrease event could be dispatched on the same day. If the evening event were to have its own day-of adjustment factor, the adjustment hours used in the calculation (12 PM – 3 PM) would overlap with the 12 PM – 1PM increase event.

### 6.4.2 Availability

The initial phase of the XSP was very flexible for participants, providing them nearly complete freedom to choose hours of availability. While reasonable to test the construct, it did reduce the chance that participants would be available coincident with actual excess-supply need. For the XSP to expand into an at-scale program, it is critical to ensure there is availability of participation across a broad range of hours. There are several ways this might be accomplished:

- Define several fixed availability windows similar to the statewide Capacity Bidding Program (CBP). Different periods of time could have different incentive levels depending on value to the grid.
- Continue to provide freedom to participants and expect scale of the program to naturally cover the hours of need.

The change from nearly 24-hour availability hours to the set times of 8-4 PM align with the former approach.

### 6.4.3 Energy Payments

Unlike the SSP II where participants may receive wholesale market energy payments, participants in the XSP did not receive any energy payments. This was due to the XSP not being integrated into the wholesale market (thus not having access to negative energy prices) and because pilot events were generally not tied to actual wholesale market conditions. However, in the future, as more

pilot events are based on actual wholesale market conditions and as new DR products are developed, another program design aspect – and possible source of funding – could be to provide payments/credits to enrolled customers when their response to an XSP event reduces the energy costs to the LSE. This could take the form of:

- A wholesale energy payment for increasing load during negative wholesale prices (the way PDR resources currently receive a wholesale energy settlement for reducing load) for resources that are integrated into the wholesale market,
- Retail credit to the participant (directly to the customer or to a 3<sup>rd</sup> party aggregator) based on the reduced amount of costs incurred by the LSE for reduced generation expenses and/or not having to pay to curtail renewable resources.

If an energy payment were incorporated into the XSP, the level of the currently constructed participation payment would be reassessed and could be reduced or eliminated.

#### 6.4.4 TOU Demand Charge Offset Payments

As mentioned throughout this section, compensating customers for retail bill impacts due to potential increased TOU demand charges because of participating in the XSP is one way to increase customer interest. However, this was always intended to be a temporary “safety net” solution exclusively for the pilot and not meant to be implemented long term. As TOU periods are shifted to later in the day over the next several years, retail peak TOU periods should better align with wholesale market peaks, reducing the conflicting signals created by asking a participant to increase load due to excess supply in the wholesale market during a retail peak TOU period. The Demand Charge Offset can then be discontinued.

In addition, as demonstrated by many of the pilot participants, it is possible, even with current retail TOU periods, for many commercial customers to increase load without incurring additional TOU demand charges. We would expect this trend to increase as participants get more comfortable with the concept of shifting load to the middle of the day and refine their bidding behavior.

Not having to calculate the Demand Charge Offset will be helpful for administration of a program with a large number of participants. Having to calculate program performance in addition to TOU demand charges incurred in response to XSP events in and of itself is an operational challenge because it requires another calculation process as well as additional data related to the customer’s retail billing process.

#### 6.4.5 Geographic Granularity

An additional aspect of this is to consider that the value of XSP might differ greatly by location, and that the CAISO-centric Sub-LAP construct is likely far too large of a regional definition to be suitable to resolve distribution-level over supply conditions. A program that is dispatchable at a level more granular than sub-LAP, such as circuit level, would likely be more beneficial as a distribution-level resource.



## 7 Conclusion and Next Steps

As discussed in Section 6, the XSP has resulted in a variety of lessons learned, for participants as well as PG&E, and, in doing so, has directly and indirectly addressed multiple barriers to renewable integration challenges. In addition, these learnings have helped inform ongoing proceedings at the CPUC and CAISO. However, there are still unanswered questions around what should trigger an excess supply event, the effects on customer bills, the effects on local distribution operations, and the interaction with other DR programs that provide demand and energy reductions.

### 7.1 Next Steps

The XSP has been successful in gaining learnings in a number of its key objectives and, in doing so, has directly and indirectly addressed multiple barriers to renewable integration challenges. In addition, these learnings have helped inform ongoing proceedings at the CPUC and CAISO. The XSP is also being looked at and utilized by other groups. For example, site hosts in PG&E's Electric Vehicle Charge Network (EVCN) program can meet the EVCN's load management plan requirement by participating in the XSP. Including EVCN participants in the XSP will enable the pilot to incorporate a technology (electric vehicles) and customer classes (smaller commercial and multi-unit residential) that have been absent from the program.

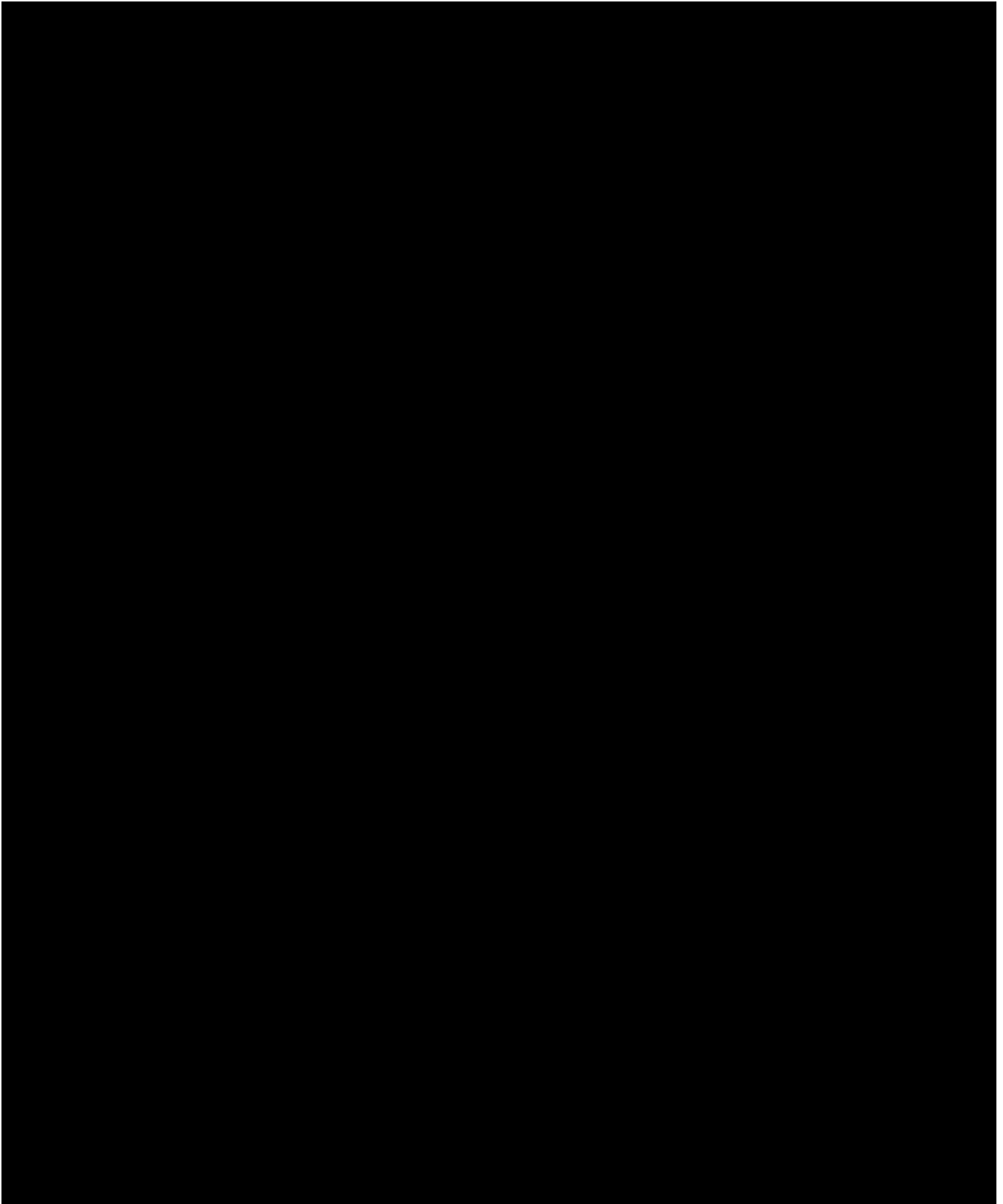
While much has been learned, there are still unanswered questions around what should trigger an excess supply event, the effects on local distribution planning and operations, and the interaction with other DR programs that provide load reduction. Based on feedback and learnings from the XSP so far, and as part of continuing to gain insights into the previously mentioned issues, the following efforts are being planned for the XSP:

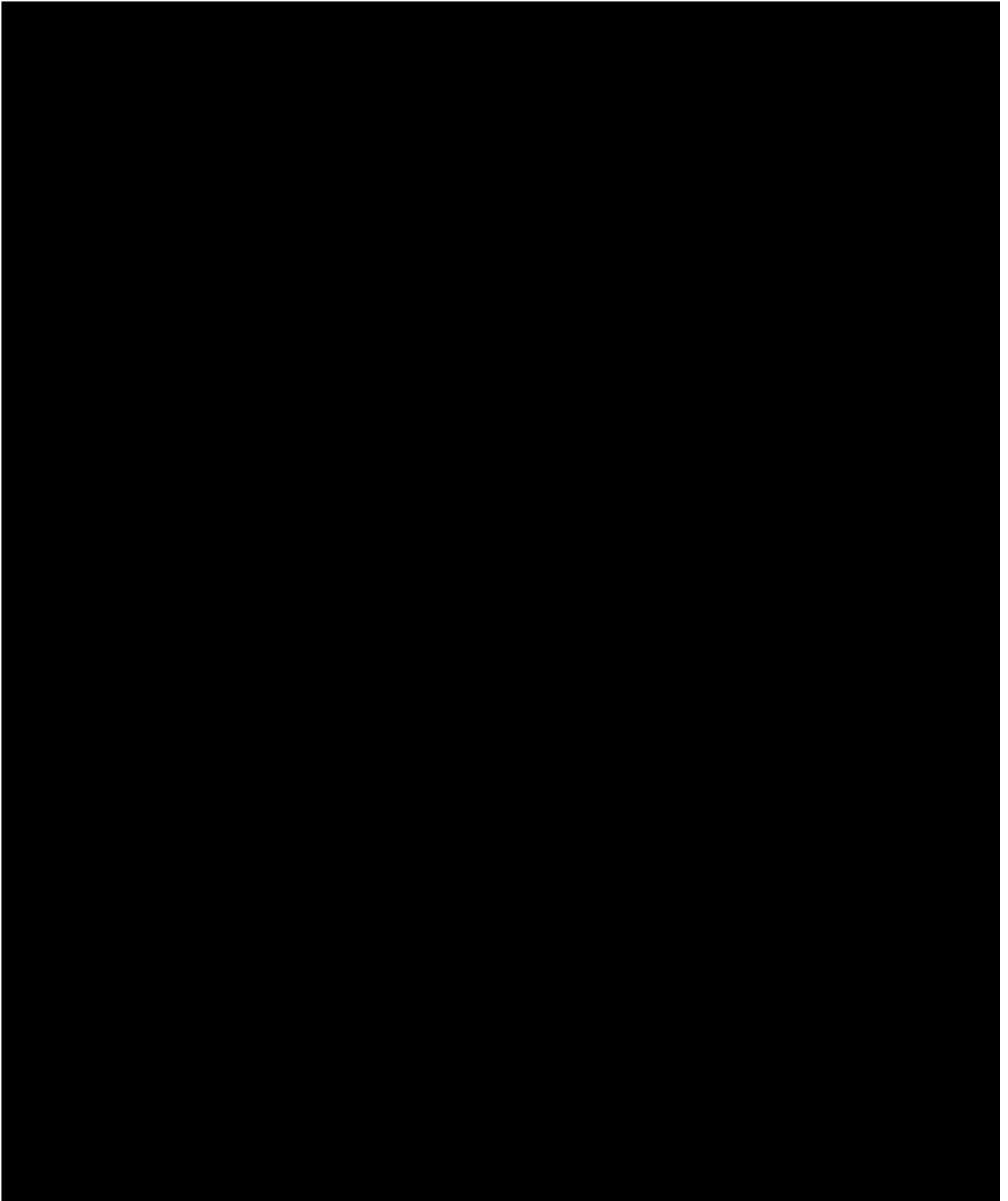
- Continue to refine the event trigger mechanism to trigger events when excess supply situations are likely to occur based on actual market conditions;
- Continue to provide real-world input into ongoing stakeholder efforts at the CPUC and CAISO;
- Evaluate the value of negative market prices to the incentive structure;
- Continue with the implementation of the EVCN participation option;
- Recruit new participants into XSP to robustly test the new XSP feature set delivered in 2018.

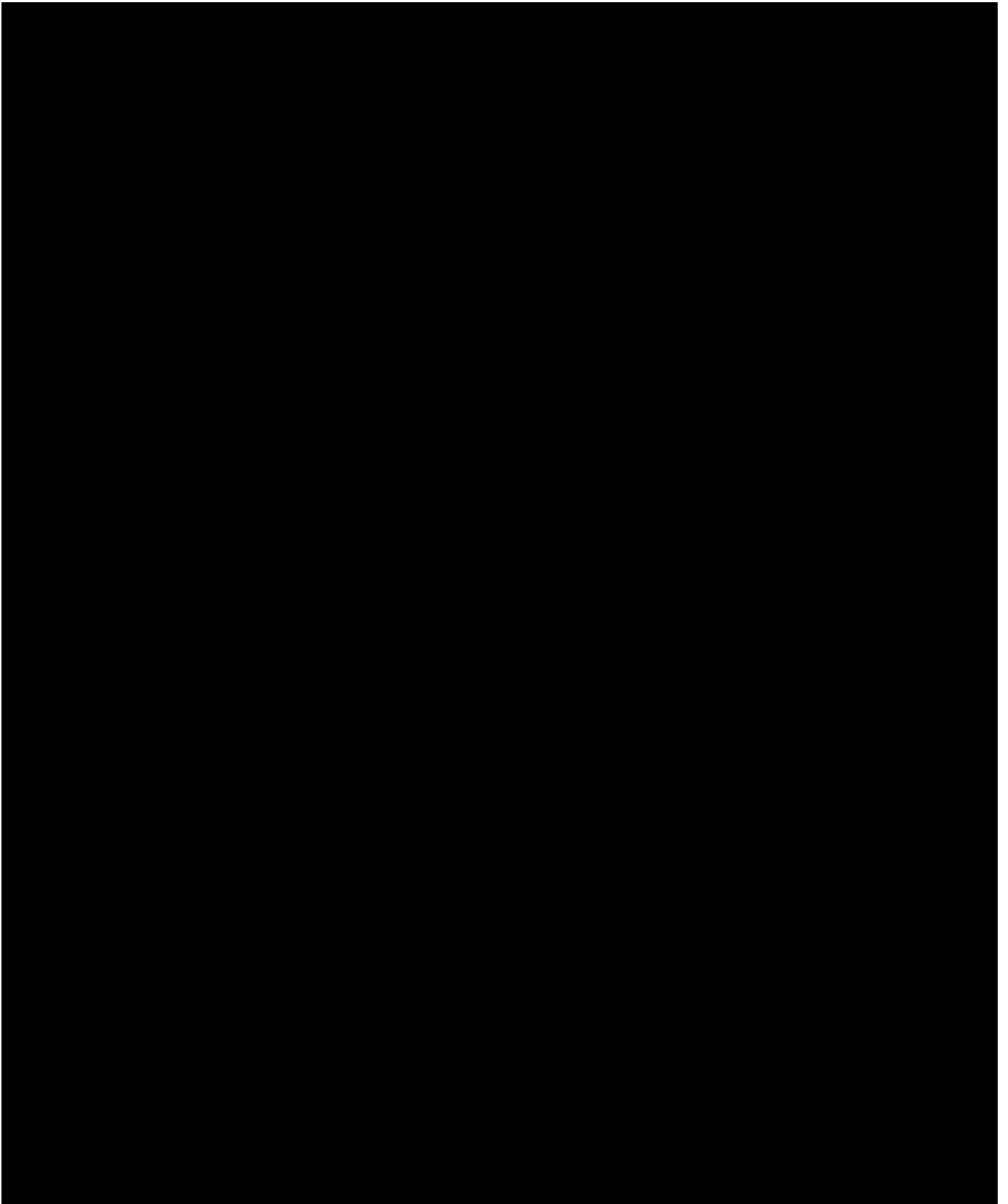
While excess supply events are already occurring and expected to grow in frequency, they are still limited. Because of this, and since there are still open questions that should be resolved prior to developing a large-scale program and which are being tested as part of the XSP, PG&E believes it is reasonable to continue testing this product as a pilot.

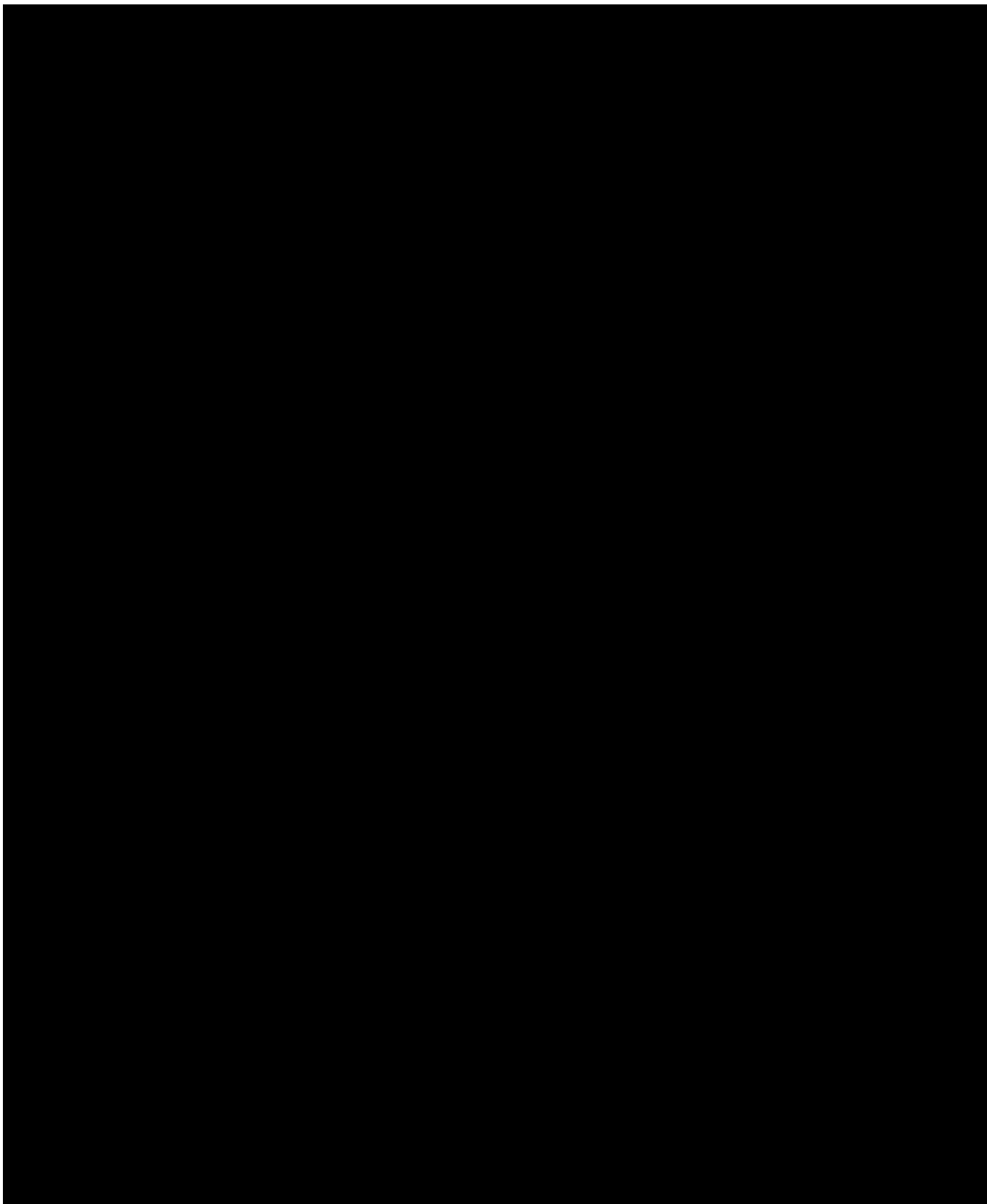
## Appendix A: Participant Performance Details

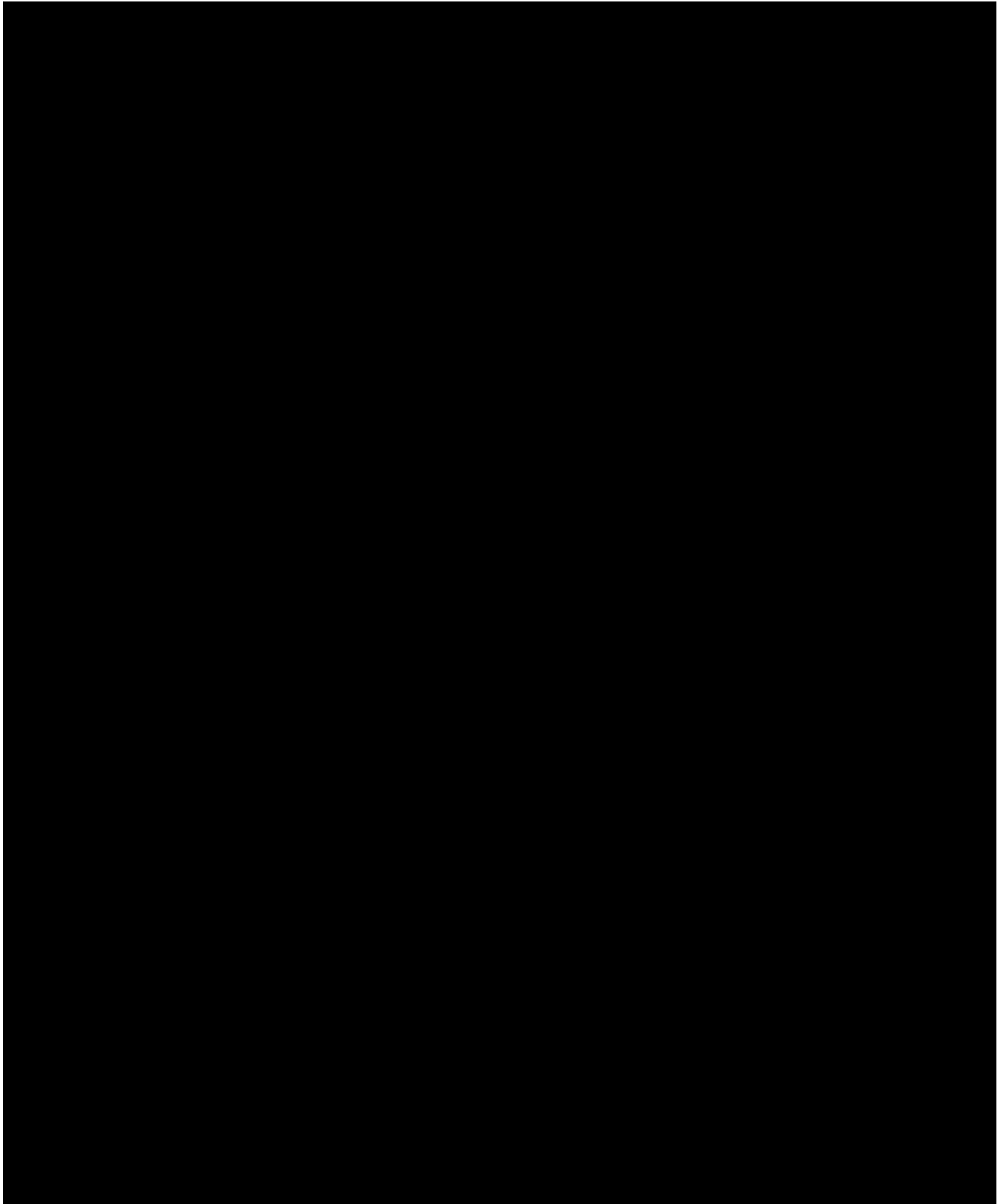
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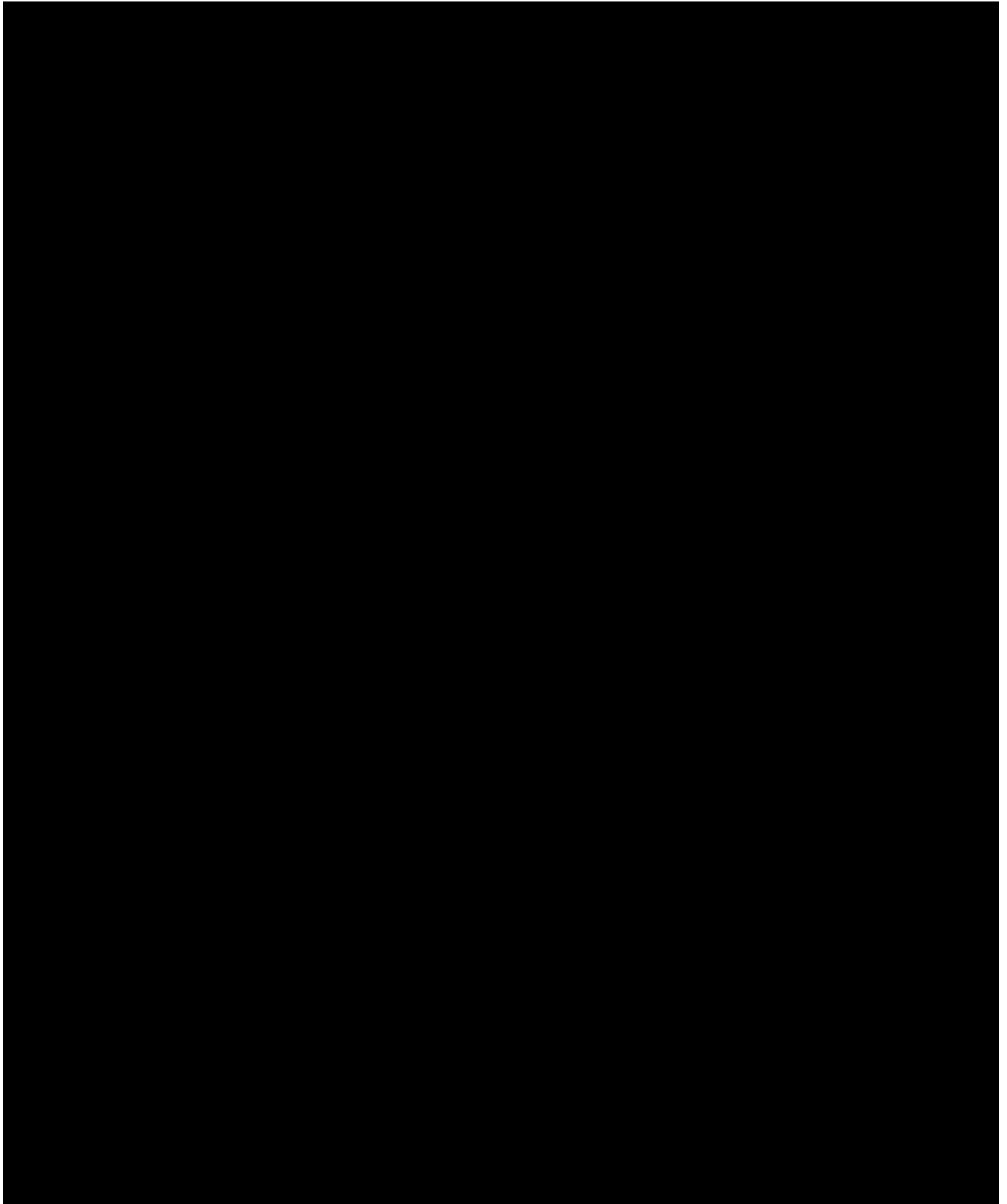




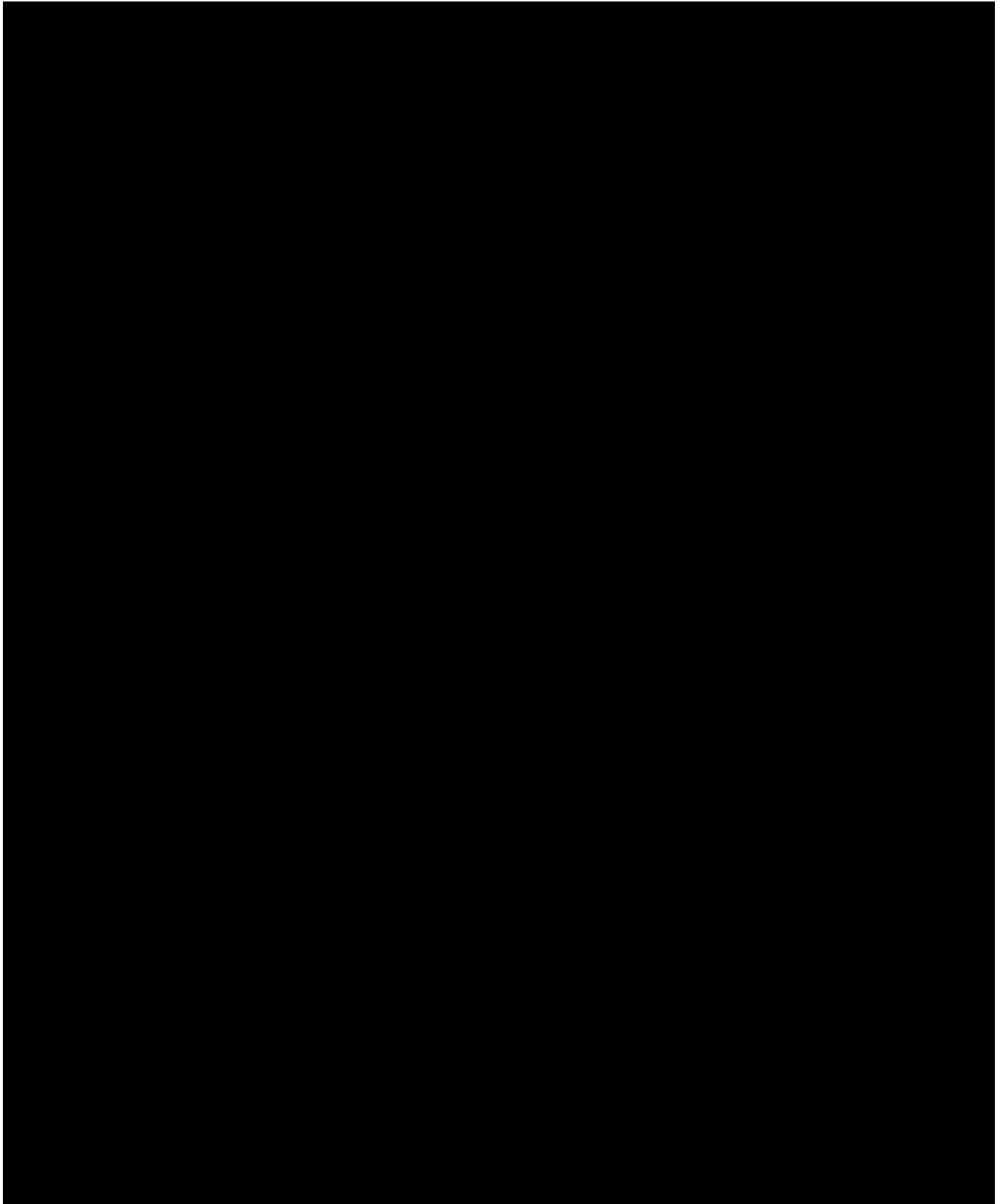


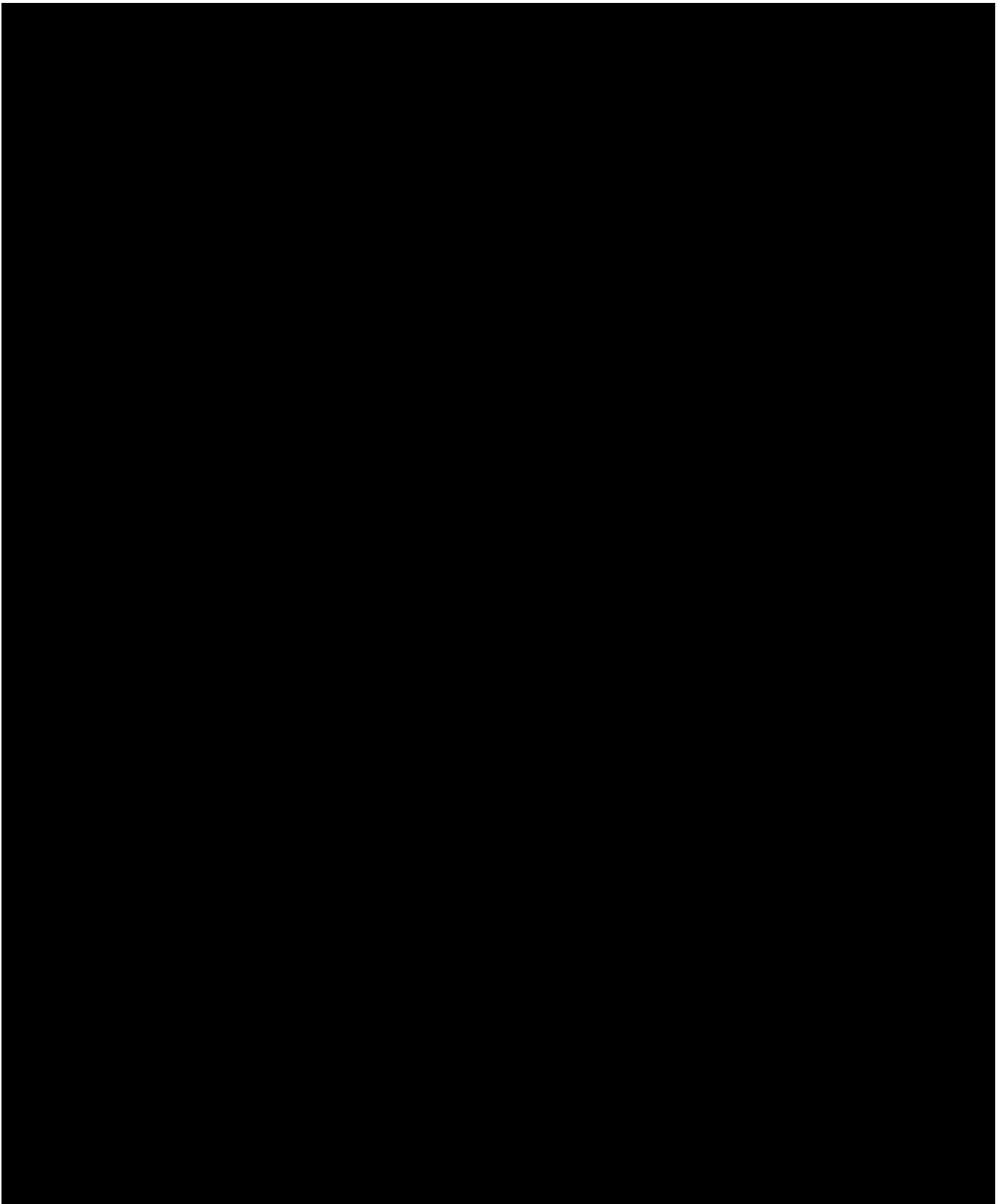


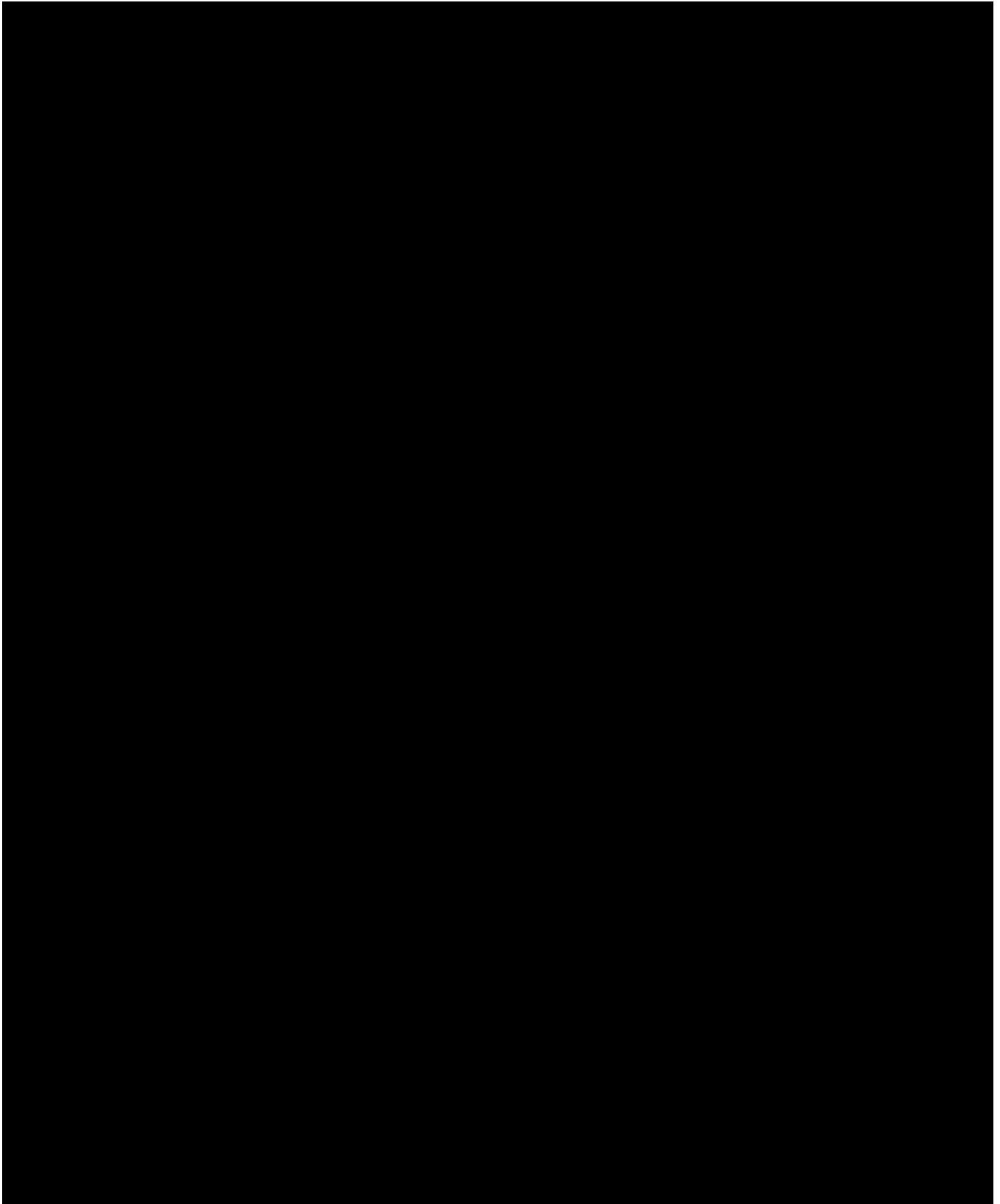


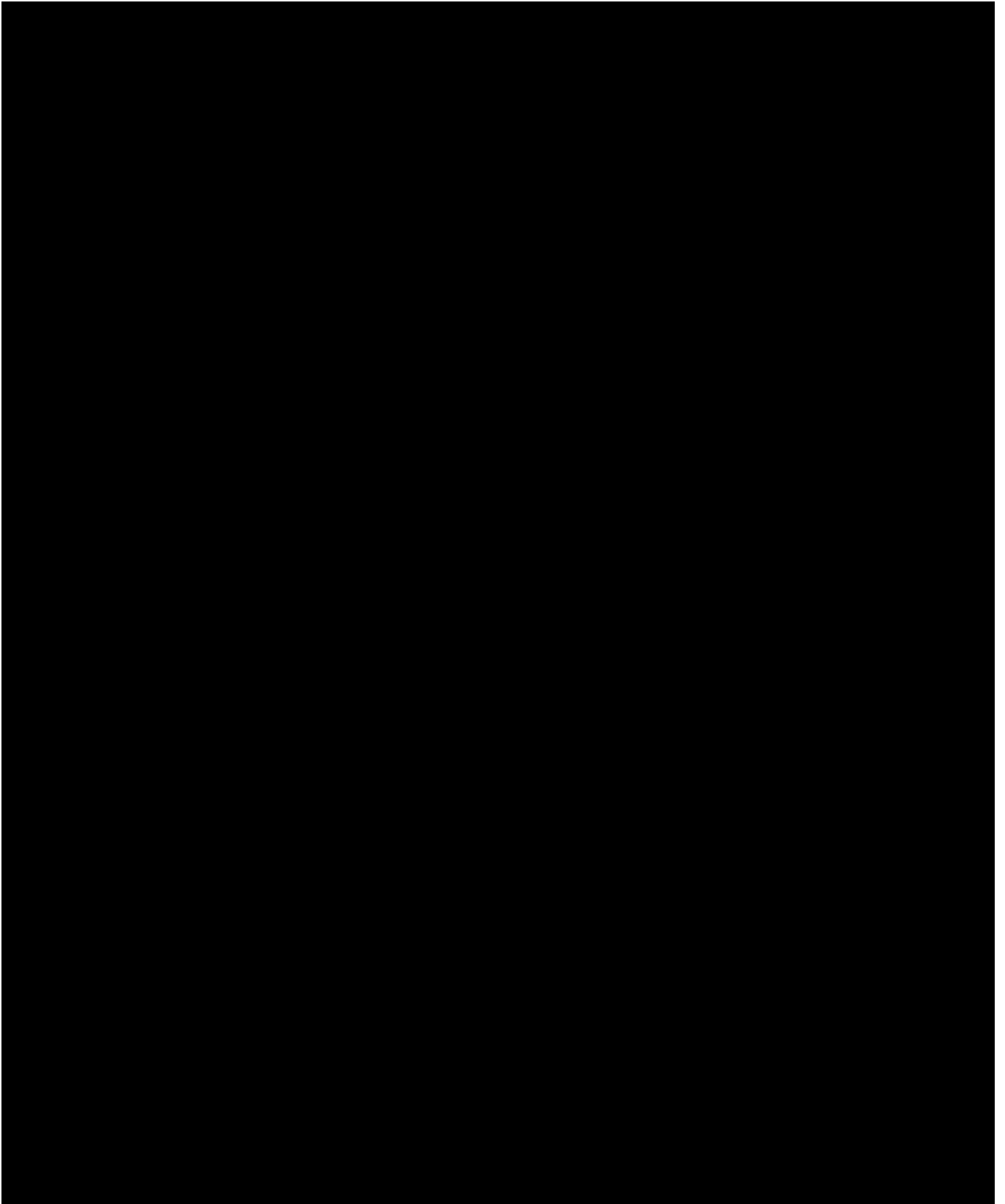


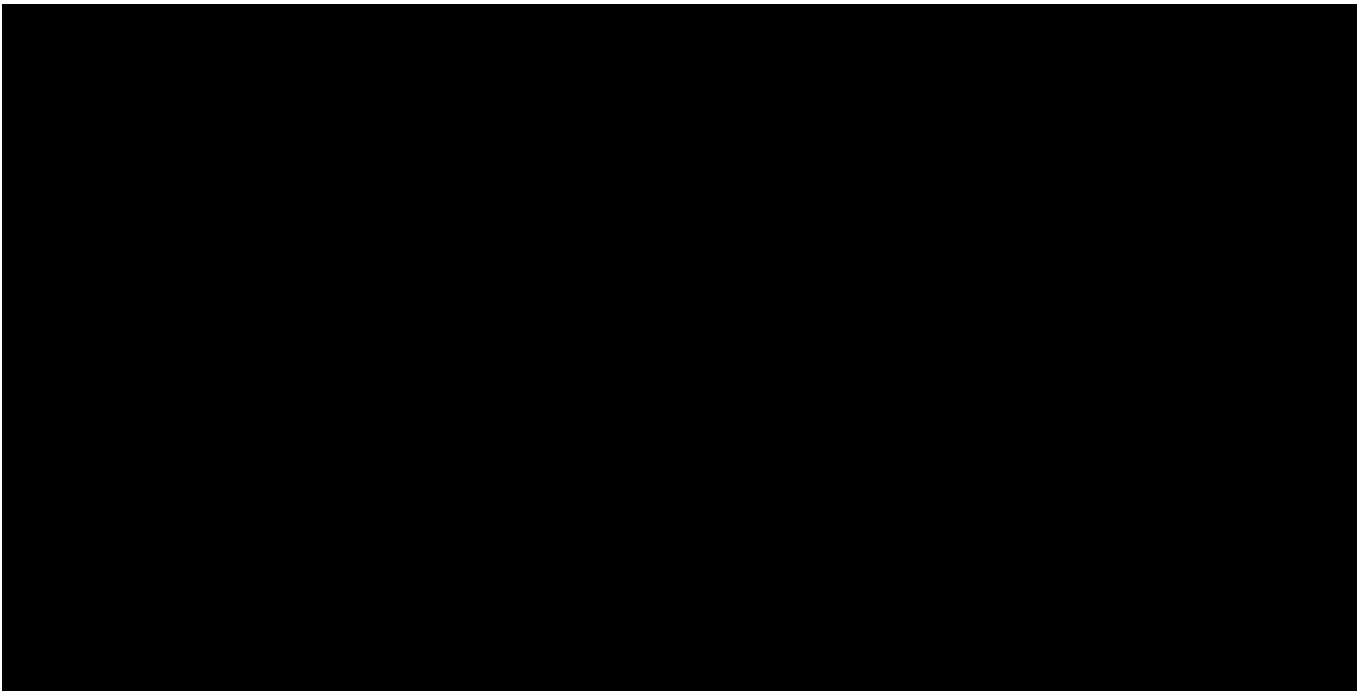
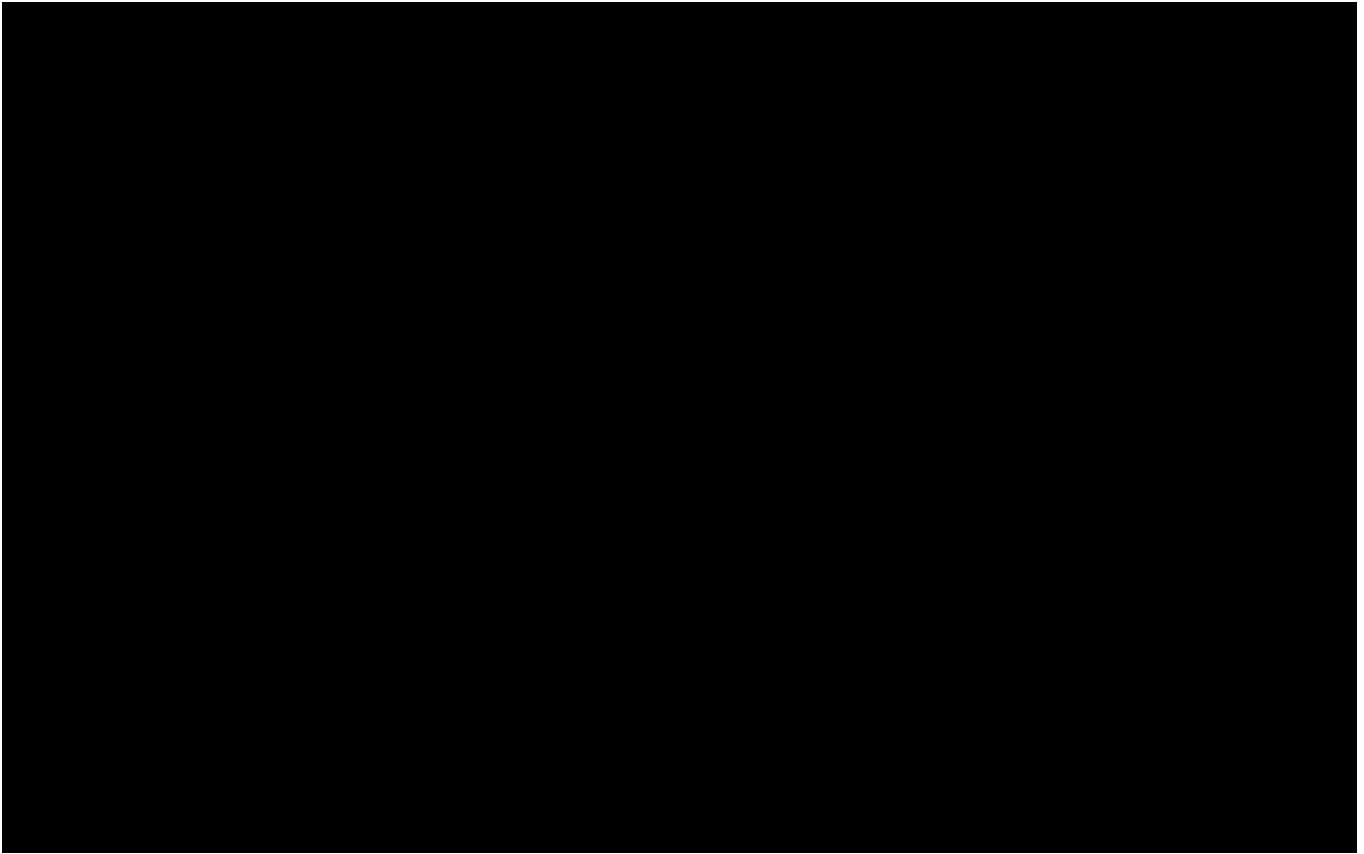


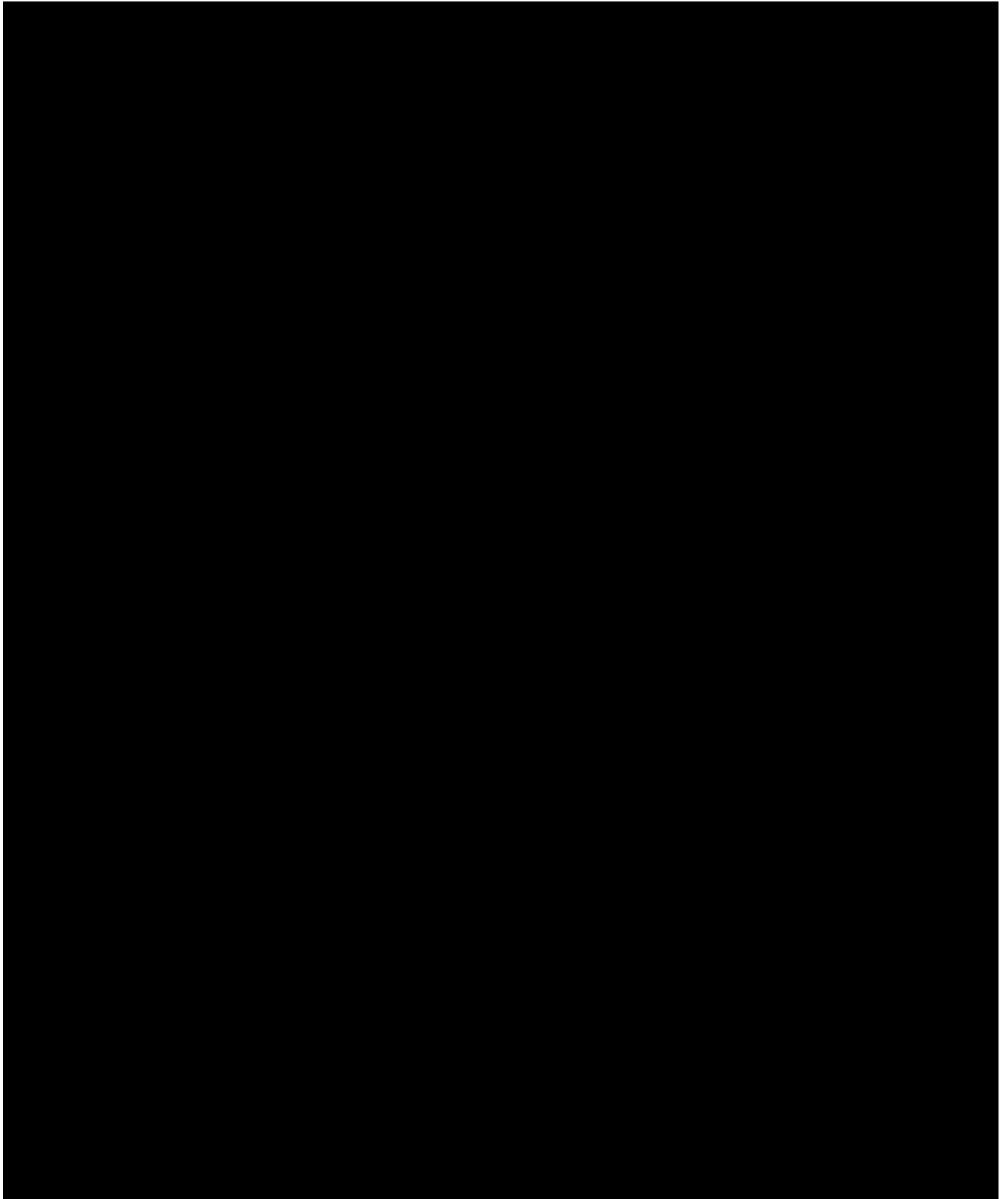


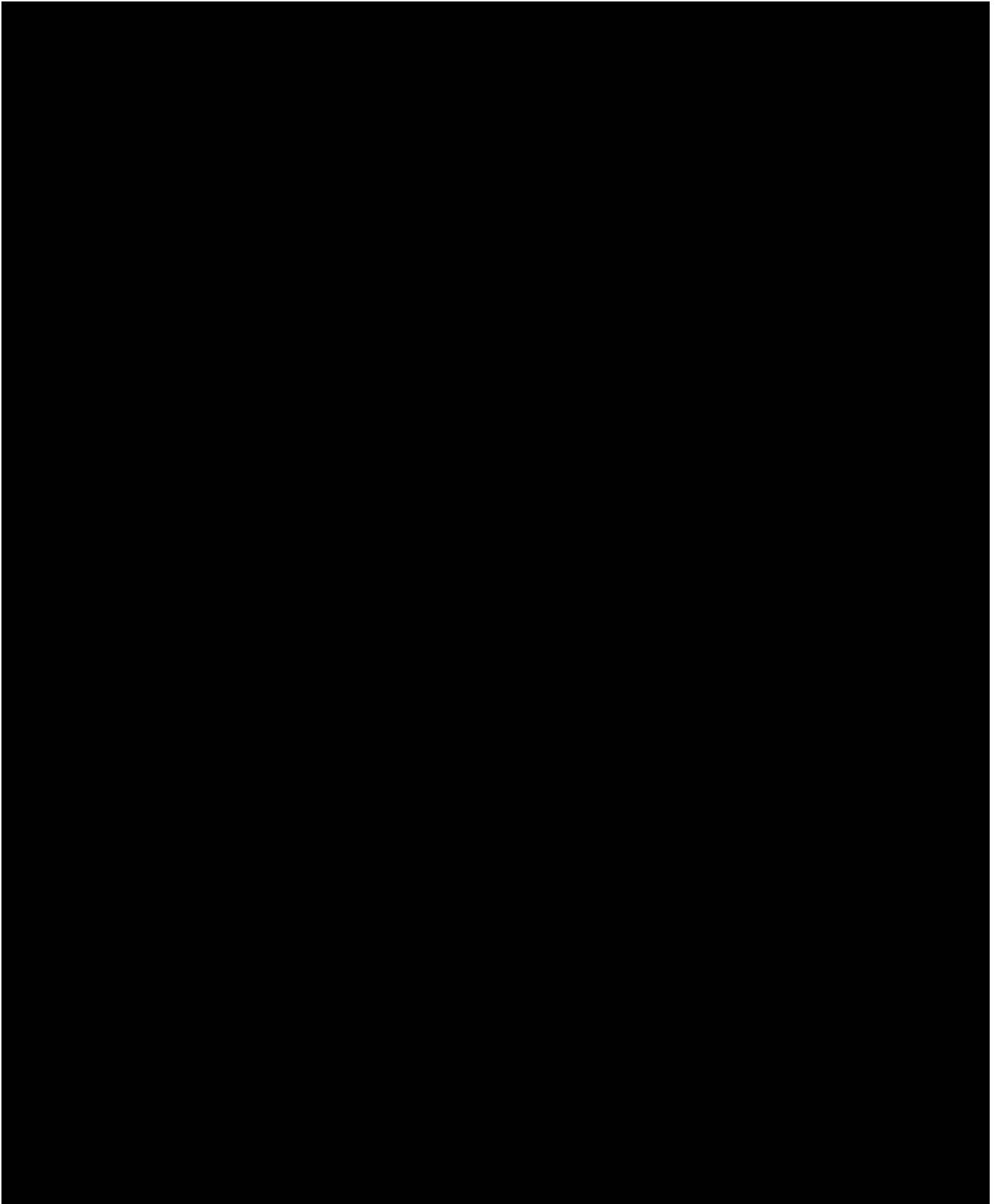


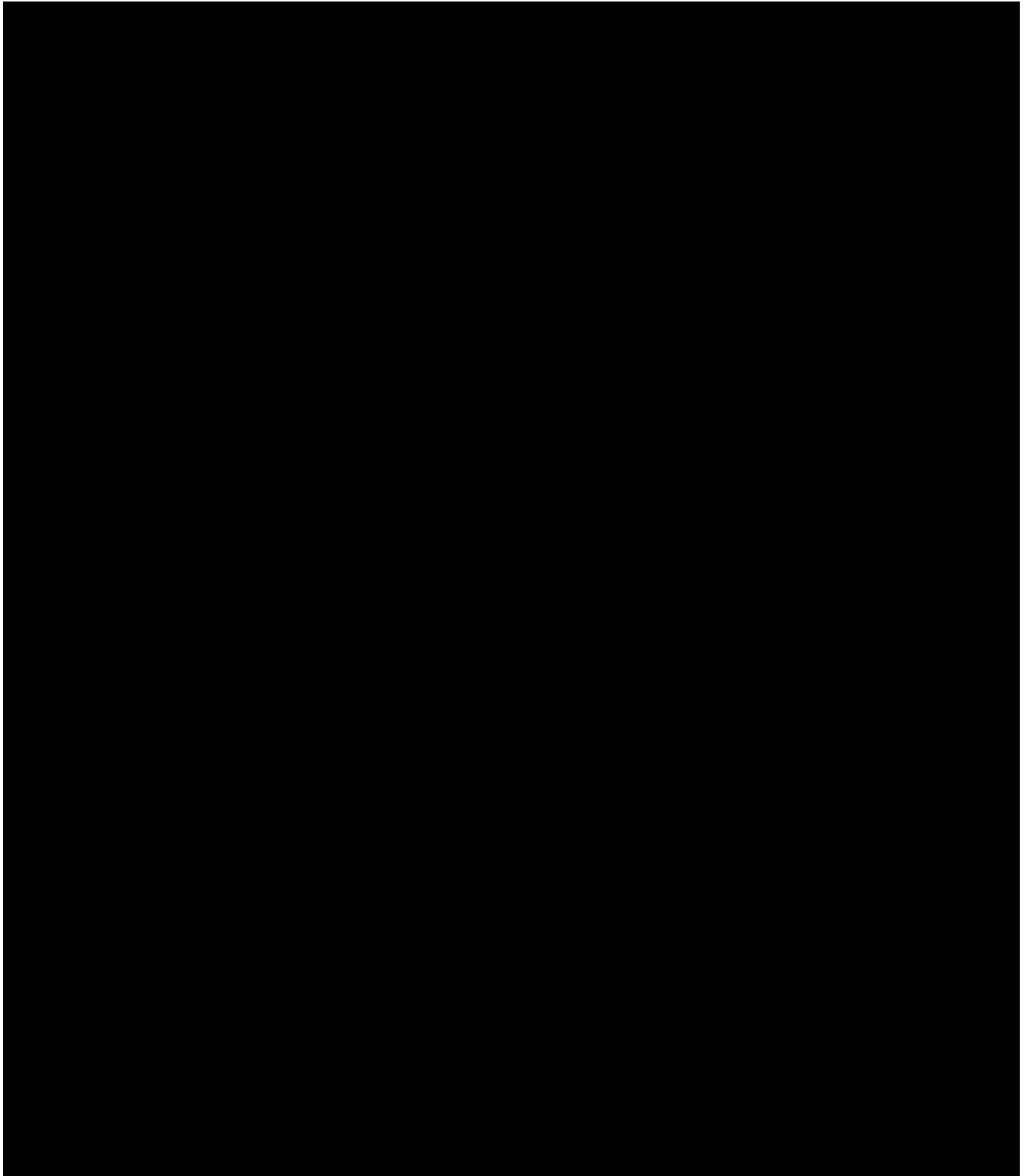




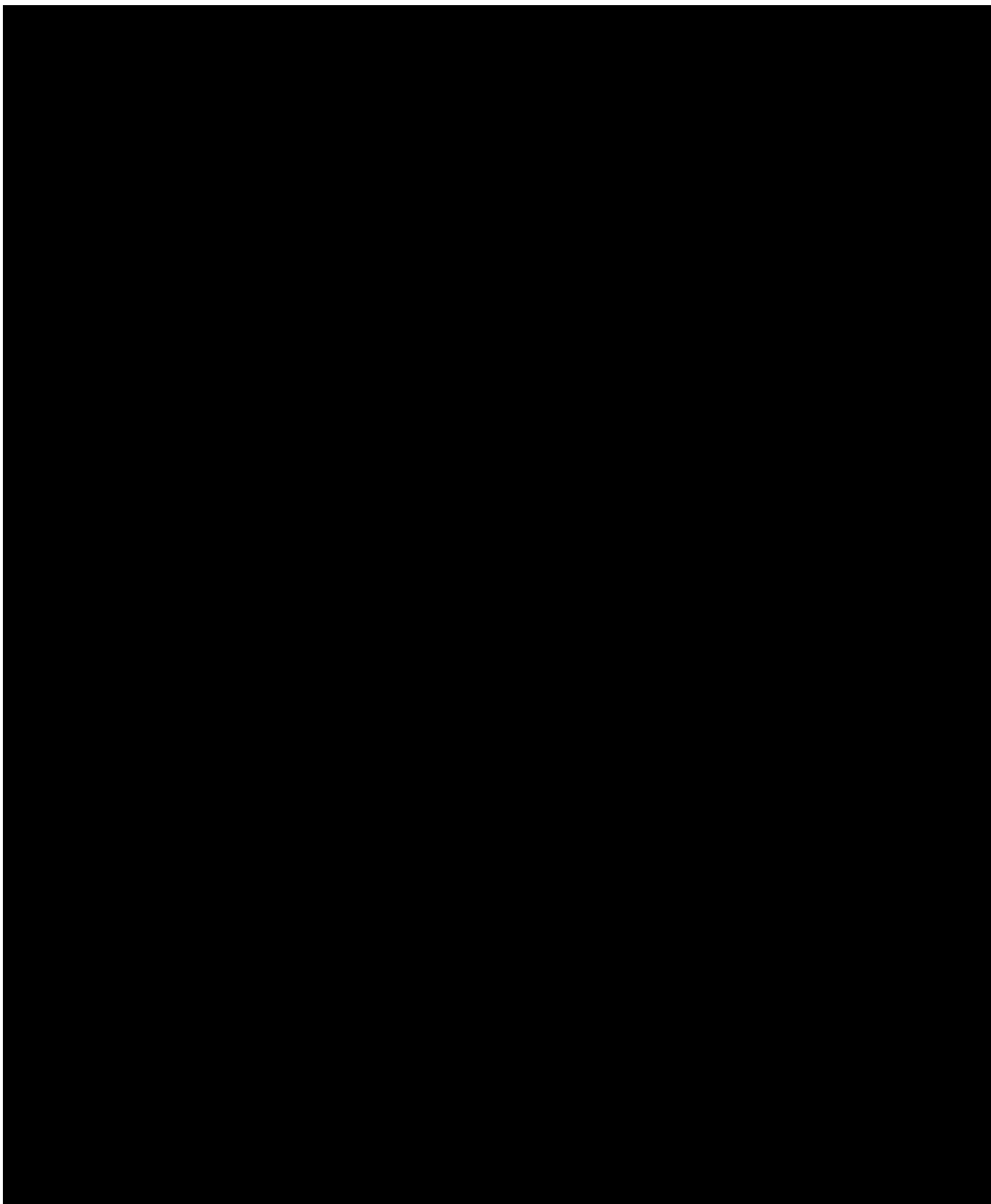


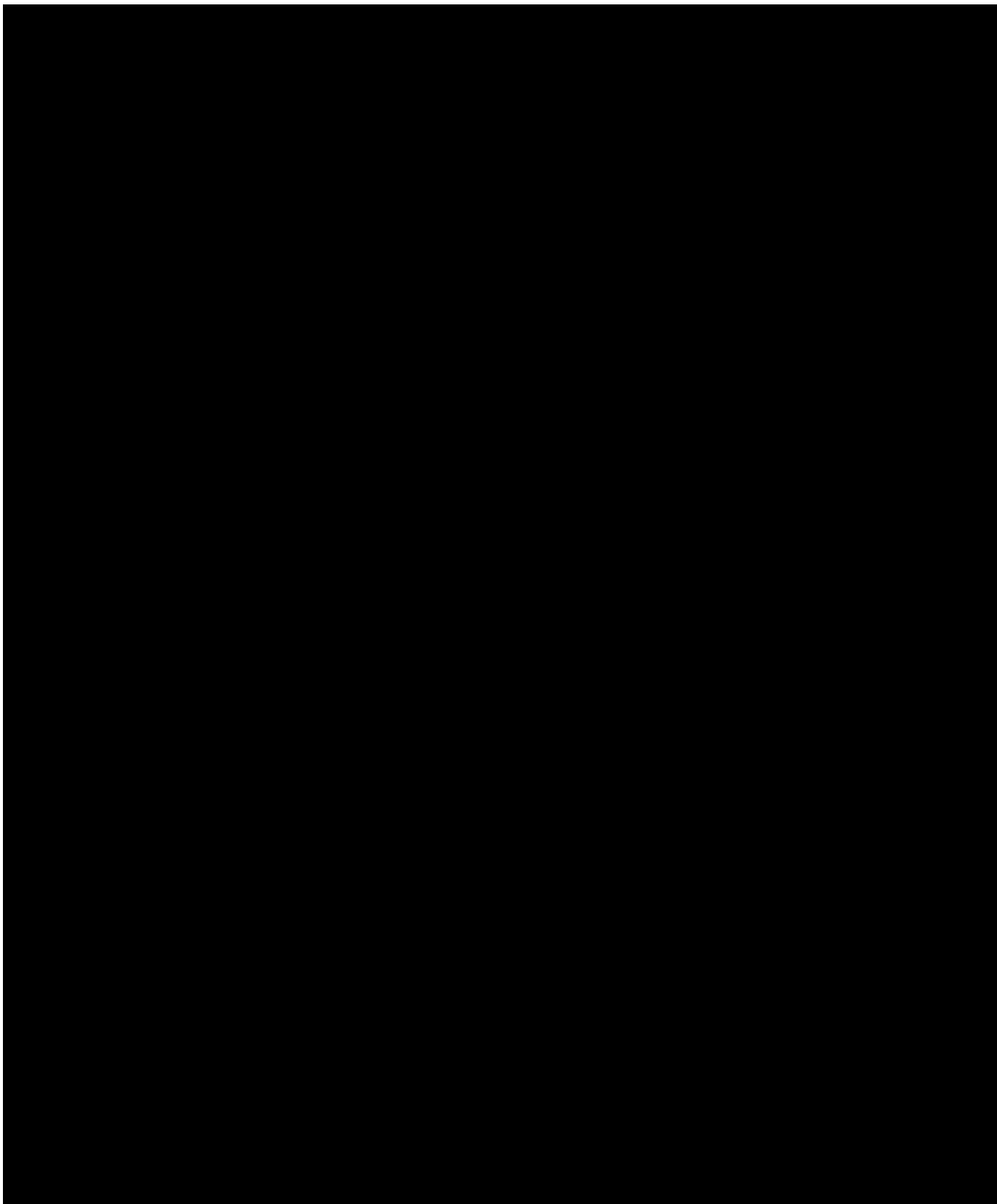


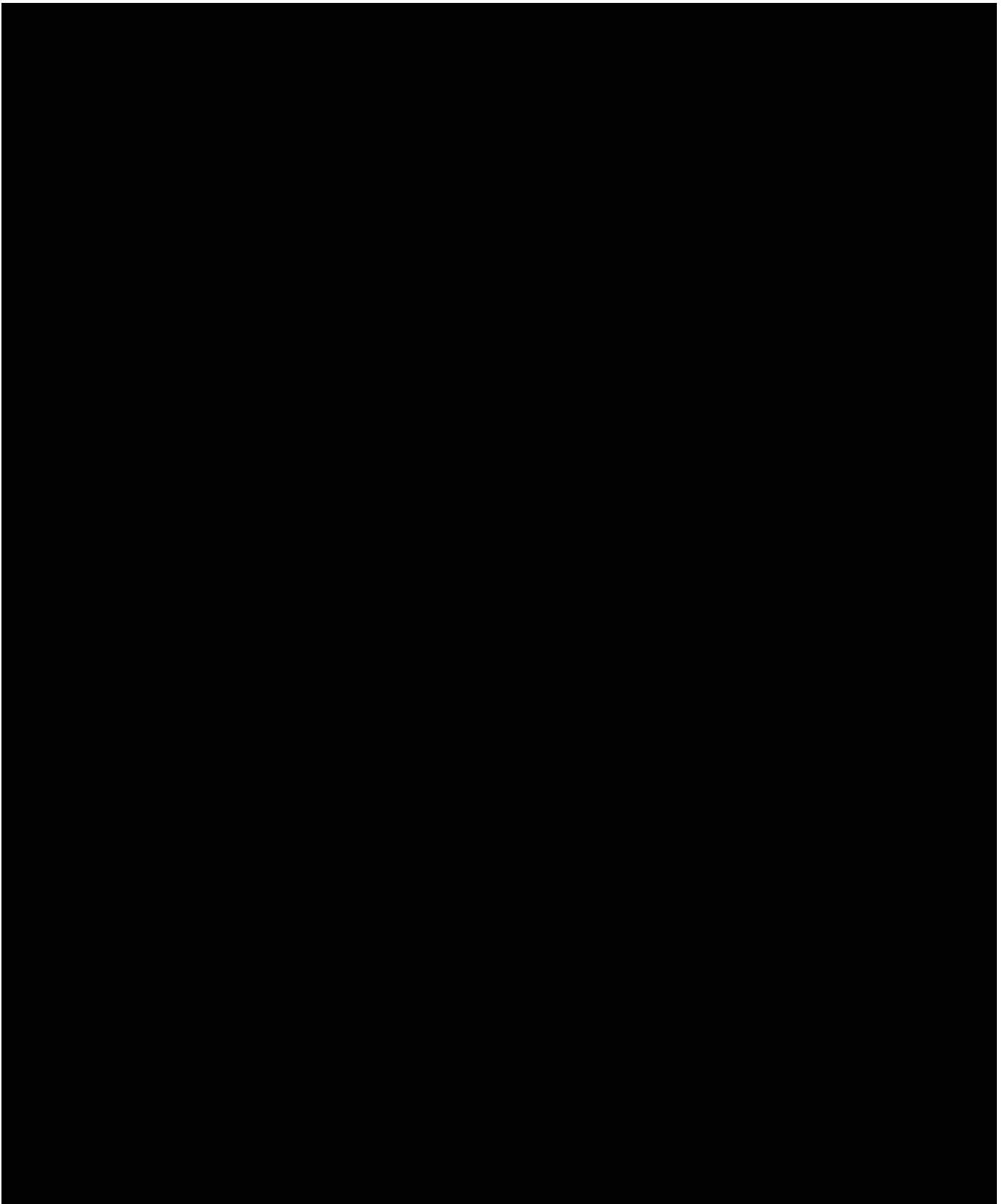


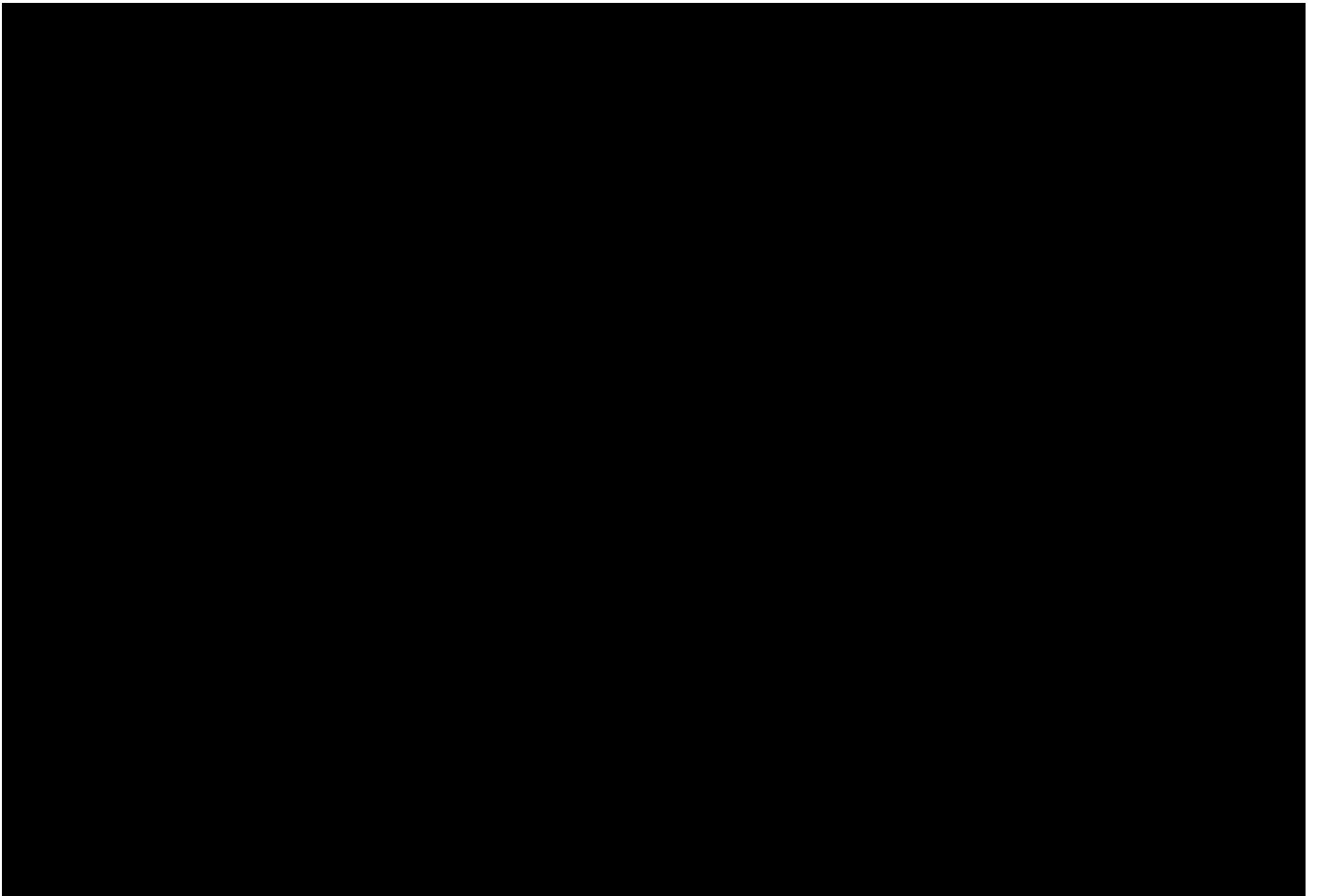
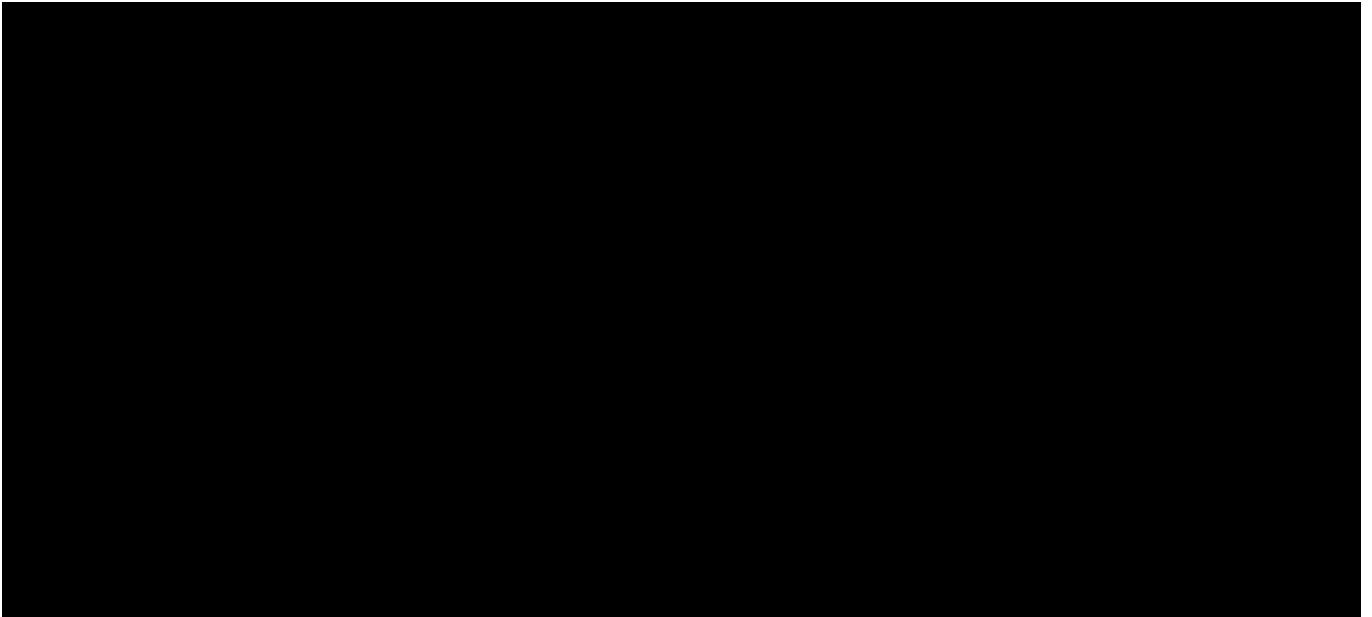


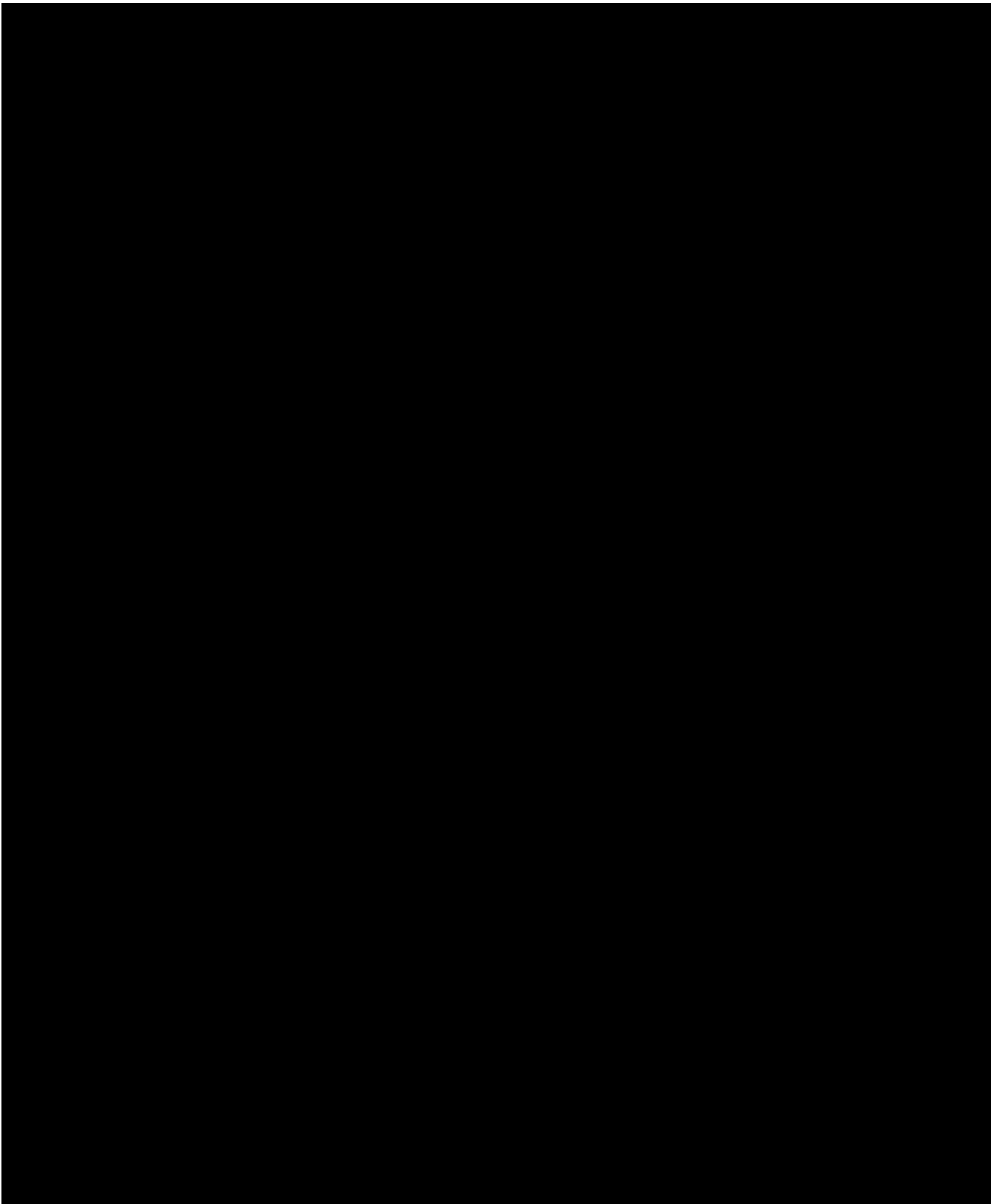


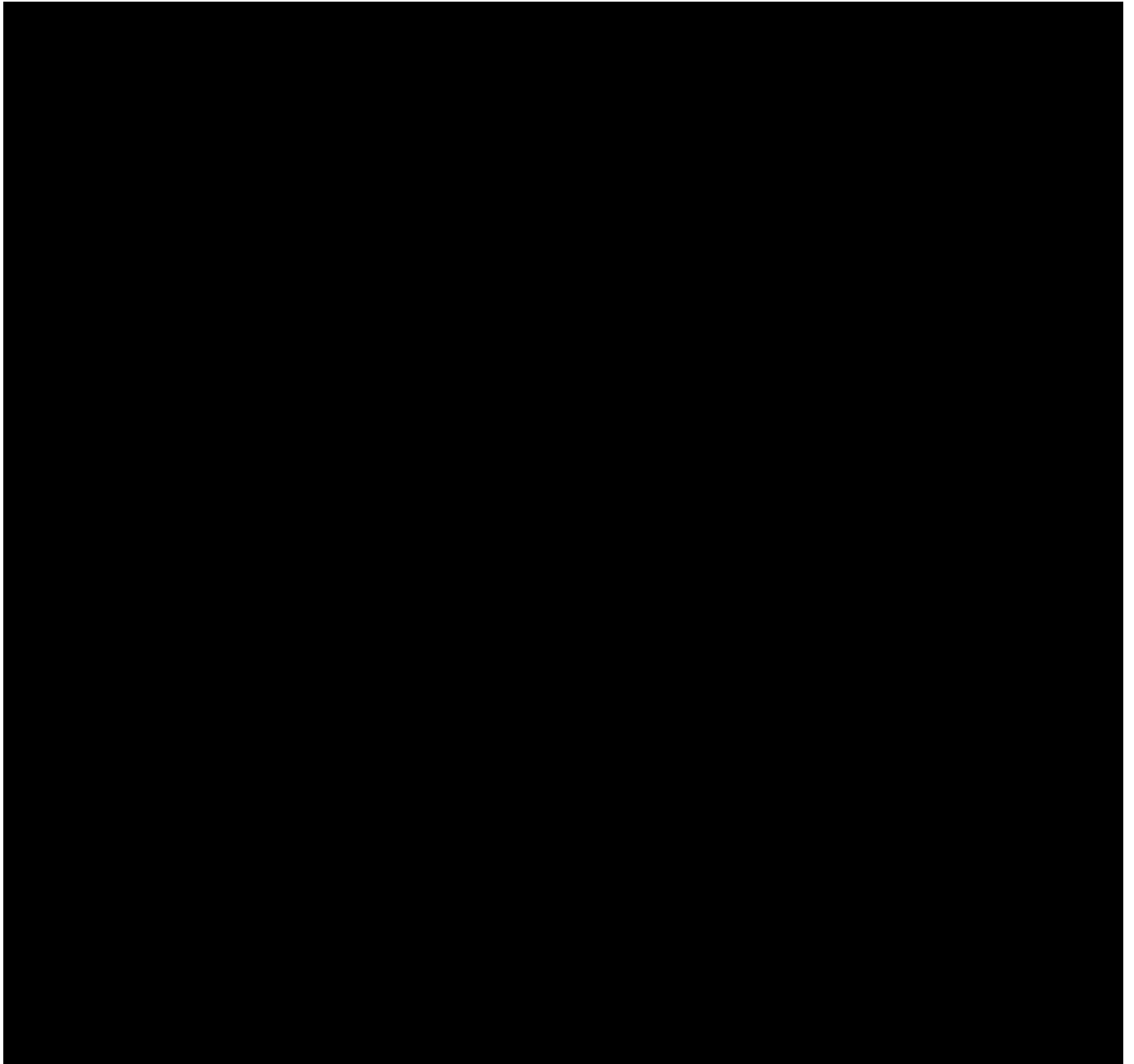












## Appendix B: Monthly Incentive Payment Details

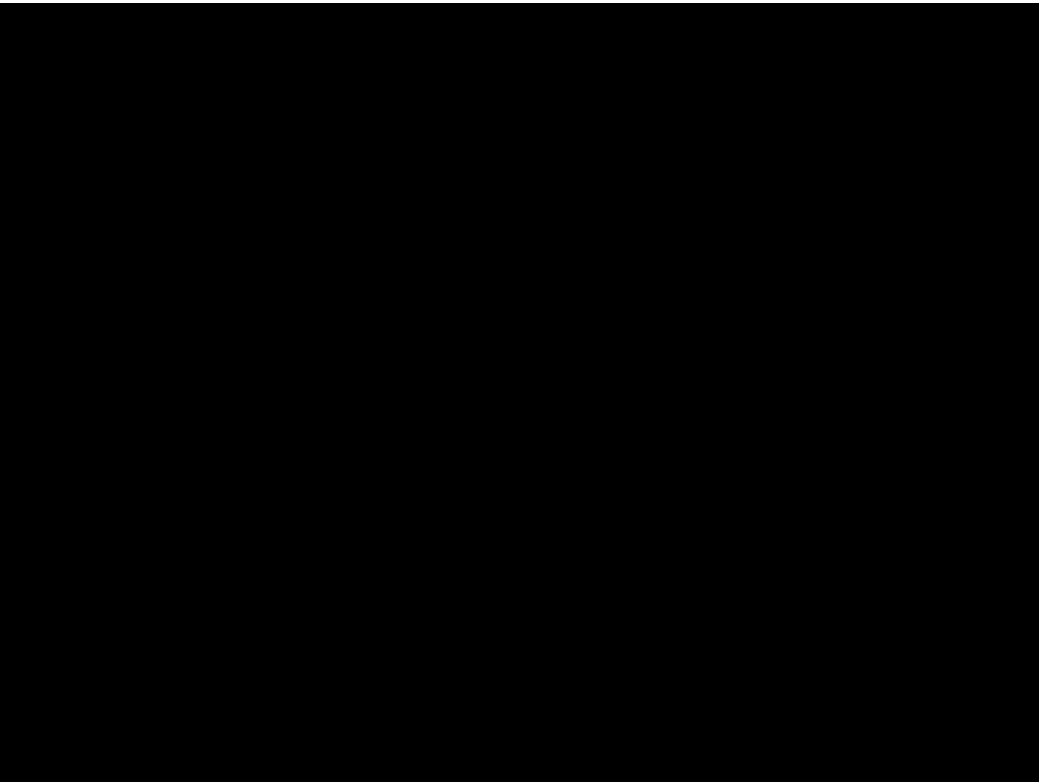
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\*See Appendix C

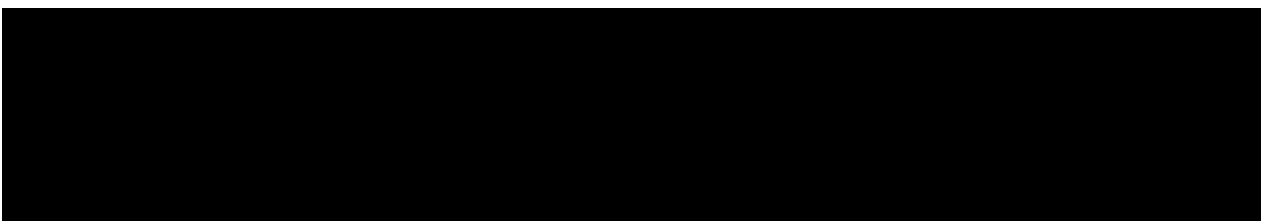
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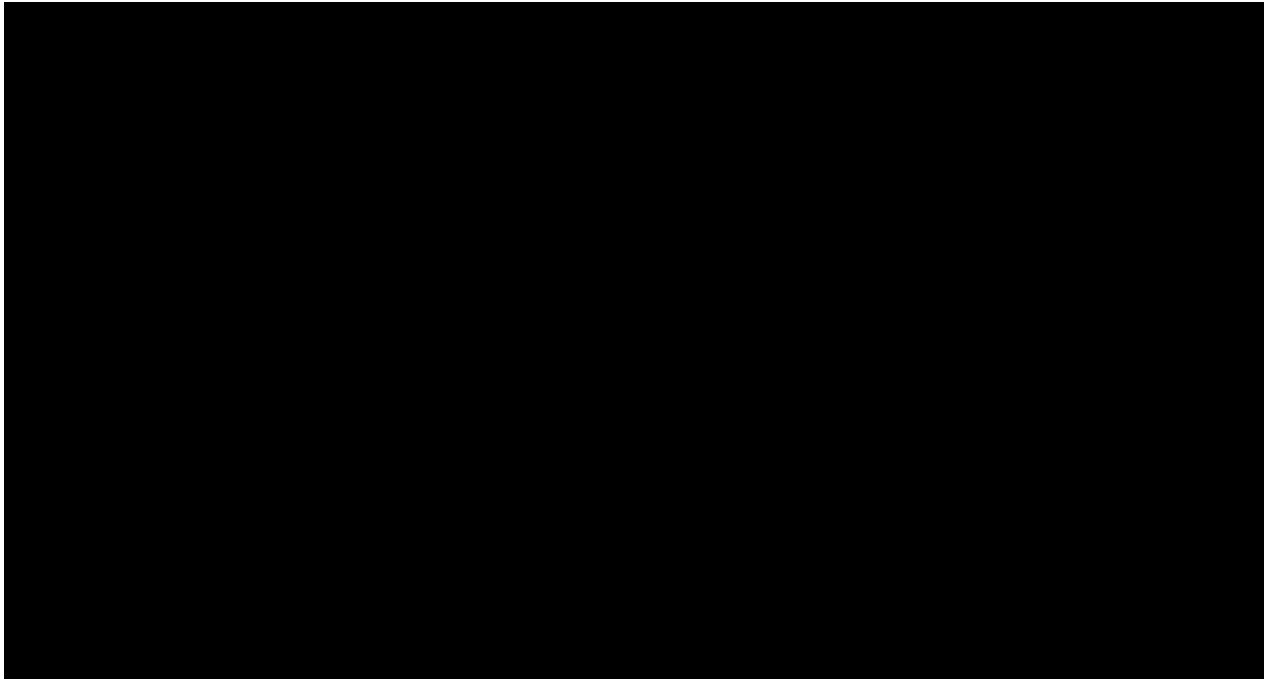
\*See Appendix C



\*See Appendix C







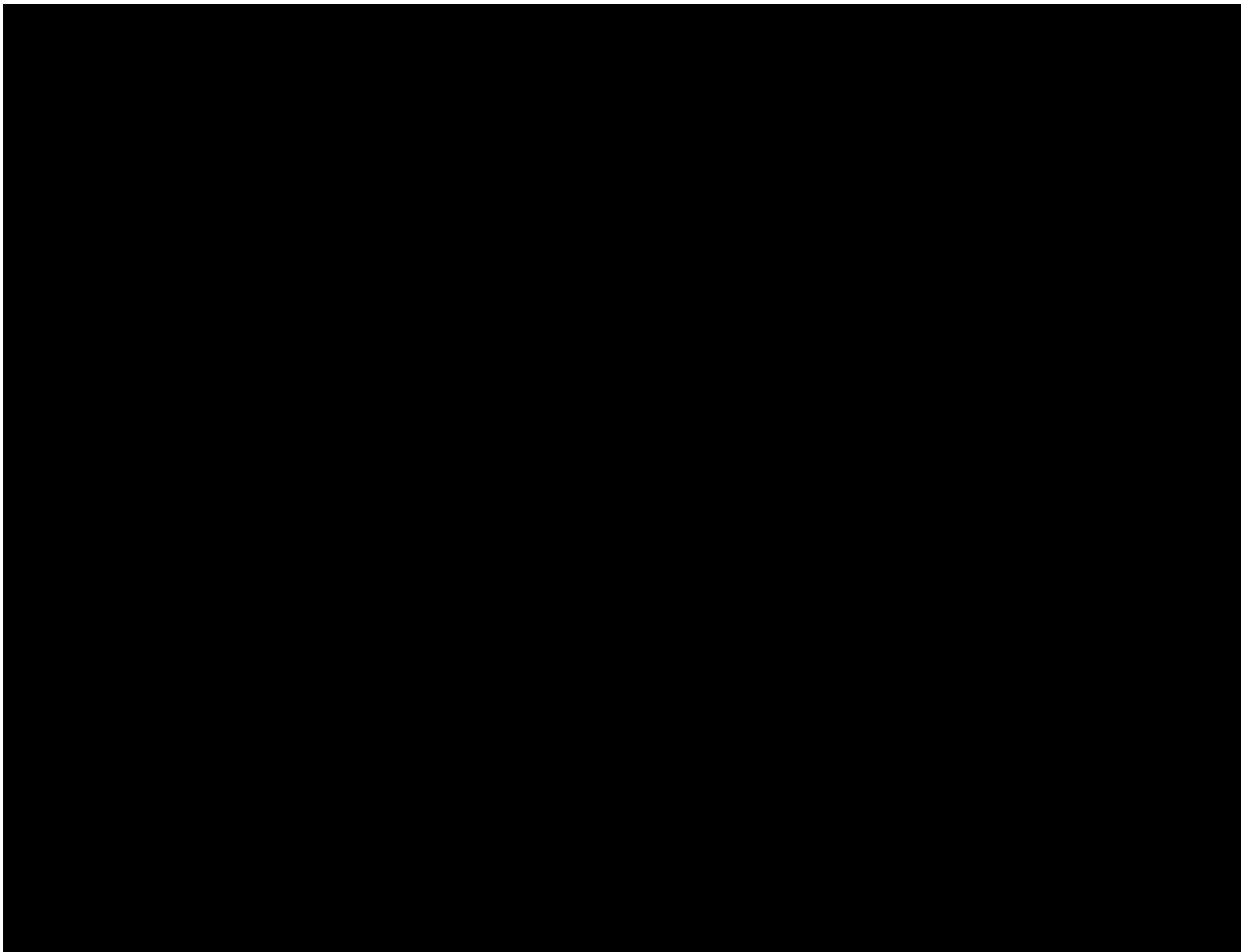
\*See Appendix C

### Appendix C: Enumeration of Payment Rounding

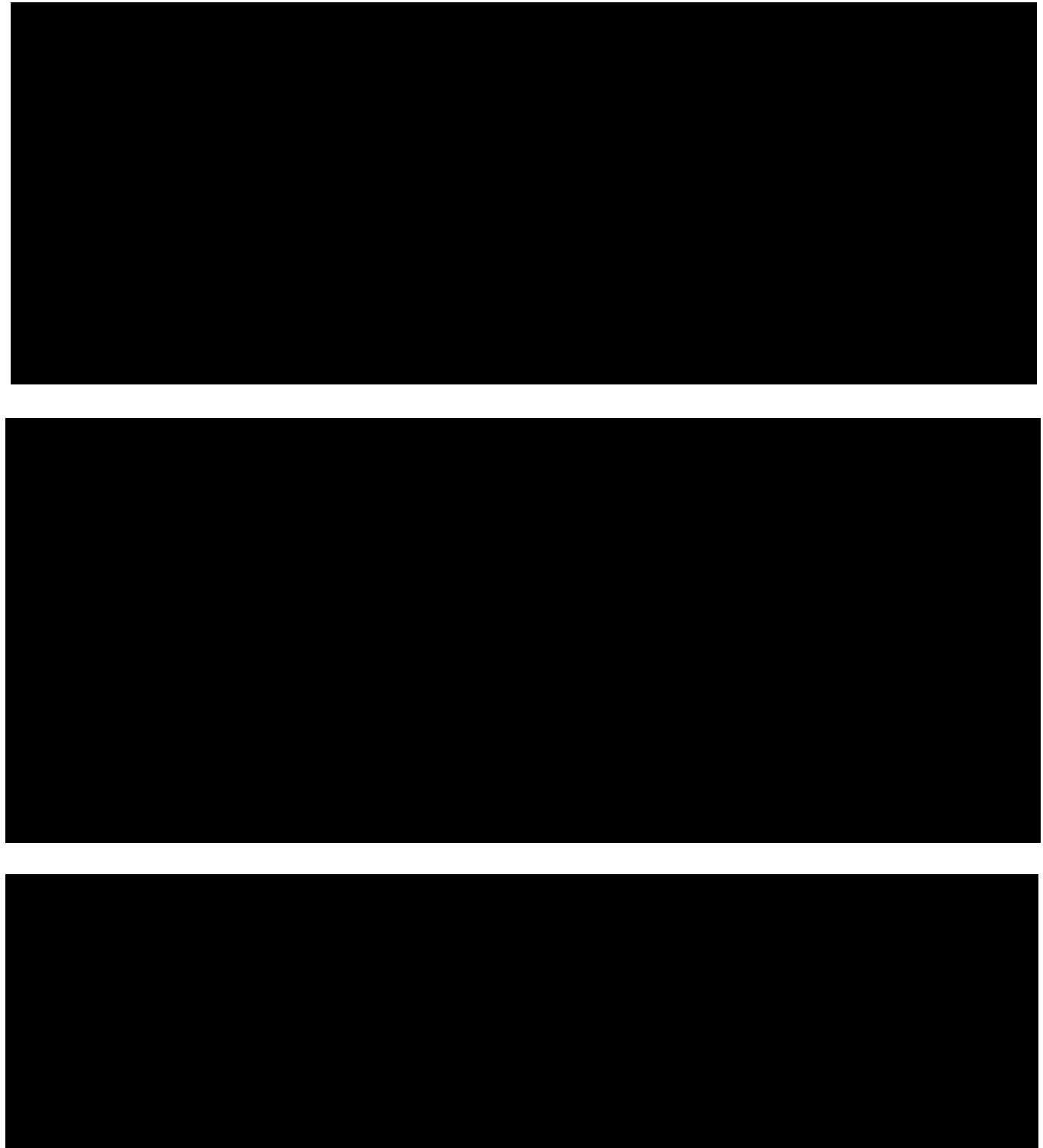
In a limited number of months, there is a discrepancy between the Raw and Adjusted Performance values in Appendix A and the Raw and Adjusted Performance values that were used to calculate participant capacity incentives. In the case of the calculation, a greater number of significant figures were used than that displayed in Appendix A. As a result, readers using the values in Appendix A to verify payment amounts in Appendix B will encounter minor discrepancies in the final amount due to rounding.

The Capacity Incentive column details the actual payments made to participants and the Expected Rounding Error is based on the values in Appendix A.

The following table enumerates this discrepancy:



## Appendix D: Historical Participant Performance Details



[REDACTED]

[REDACTED]