# R.24-01-018 – Public Workshop Discussing the Development of Energization Timing Targets and Processes to Report Energization Delays

*California Public Utilities Commission, Energy Division*

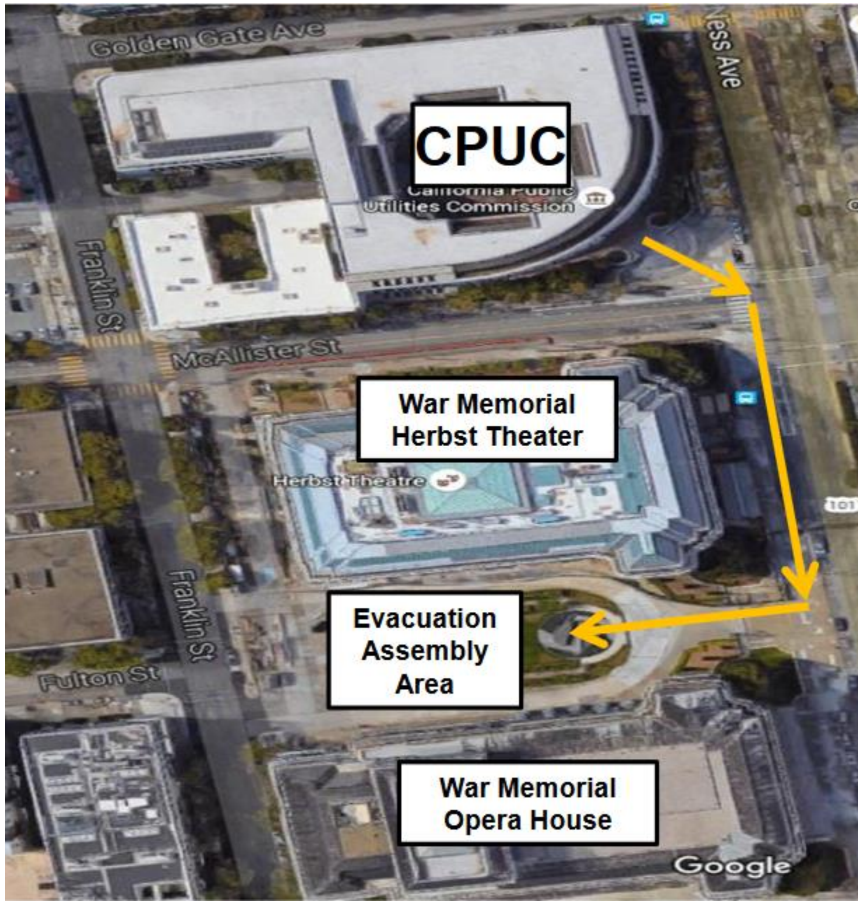
*Emmanuelle Truax, Senior Transportation Electrification Analyst*

*February 2, 2024*

California Public
Utilities Commission

# Safety & Misc.

- In case of an Emergency
  - Staff will call 911
  - To evacuate, proceed out of 1 of 4 exits to Civic Center Plaza
    - Exit toward Van Ness / McAllister
    - Walk past City Hall
- Bathrooms & water fountain across the Lobby



# Ground Rules and Workshop Logistics

- **Ground Rules:**
  - Hold all questions until the end of each panel
  - Identify yourself and your organization before speaking
  - Do not repeat what another person has already said
  - Stay on topic
- **Workshop Logistics**:
  - Workshop is being recorded and will be posted on the CPUC's webpage along with presentation slides
  - WebEx and phone participants are reminded to stay muted until called on
  - Webex participants type questions/comments to 'Chat Me!' and they will be read aloud

# Please Note

- Today’s workshop will not be on the record for R.24-01-018.
- Please ensure all crucial comments and points are included in writing to the R.24-01-018 docket.
- Parties may include information they discuss today in their Opening and Reply comments to the OIR.
  - Opening comments are due February 20, Reply comments due March 1
- Participants who are not formal parties to the OIR may either partner with respondents or contact Energy Division staff to provide additional comments, which may be incorporated into the record in the future.

# Morning Agenda

| Topic | Time |
|---|---|
| **Introduction, Ground Rules, and Workshop Process**<br>Em Truax, CPUC Energy Division | 9:30 – 9:35 |
| **Opening Remarks from President Reynolds and Commissioner Houck**<br>President Alice Reynolds and Commissioner Darcie Houck, CPUC | 9:35 – 9:45 |
| **Energization Timing Background**<br>Em Truax, Energy Division | 9:45 – 9:55 |
| **Panel 1 – Process and Data to Complete Electric Rule 15 and 16 Energization Requests**<br>Matt Ventura & Kevin Douty, PG&E; Brian Small, SCE; and Eric Turner, SDG&E | 9:55 – 10:50 |
| **Break** | 10:50 – 11:00 |
| **Panel 2: – Process and Data to Complete Investments for an Upstream Distribution Capacity Upgrade**<br>Bill Peters & Jennifer Goncalves, PG&E; Roger Salas, SCE; and Yi Li, SDG&E | 11:00 – 11:55 |
| **Lunch** | 11:55 – 1:00 |

# Afternoon Agenda

| Topic | Time |
|---|---|
| **Panel 3 - Customer Experience Requesting New or Upgraded Electric Service from the Utility – Part 1**<br>Corey Smith, Housing Action Coalition; Aravind Kailas, Volvo Group North America; and Chris Shimoda, California Trucking Association | 1:00 – 1:40 |
| **Panel 4 - Customer Experience Requesting New or Upgraded Electric Service from the Utility – Part 2**<br>Meredith Alexander, Consultant to Microsoft; Priscilla Rodriguez, California Cotton Ginners & Growers Association and Western Agriculture Processors Association; and Michelle Bushnell, Supervisor, Humbolt County | 1:40 – 2:20 |
| **Break** | 2:20 – 2:30 |
| **General Discussion on Efforts to Develop Energization Timing Targets and Reporting Energization Delays** | 2:30 – 3:30 |
| **Wrap Up and Next Steps**<br>Em Truax, CPUC Energy Division | 3:30 – 3:40 |

# Opening Remarks

# President Alice Reynolds

# Commissioner Darcie Houck

# Workshop Objectives

- Discuss the scope of the Energization OIR.
- Provide an overview of the energization processes and develop a common understanding of the steps to complete a customer’s energization request.
- Present available IOU data reflecting the historic timing to complete energization requests and discuss what additional data collection efforts are needed.
- Hear industry representative experiences going through the energization process and how delays are communicated and overcome.
- Provide a venue for stakeholders to share initial thoughts on how the CPUC should develop energization timing targets and the process for customers to report delays.

# Definitions

- **Energization**: the process to connect new load to the distribution system
- **Interconnection**: the process to connect new generation facilities to the distribution system
- **Rule 15**: standard energization tariff that covers distribution line extensions (from the substation to the secondary transformer)
- **Rule 16**: standard energization tariffs that cover service line extensions (from the secondary transformer to the meter)
- **EV Infrastructure Rules (Rule 29/45):** optional alternative to Rule 16 for customers that require a service line extension to support the energization of an EV charging project
- **Upstream Distribution Capacity Projects:** projects that address capacity deficiencies related to customer energization requests.

# Timely Energization: Critical to California’s Economy and Policies

*There are significant concerns about current and future energization delays across all of California’s major economic sectors.*

**Agricultural**

**Buildings**

**Transportation**

**Industrial**

# Senate Bill 410 (Becker, 2023) and Assembly Bill 50 (Wood, 2023)

*These bills are intended to improve electric utility processes that facilitate timely energization for electric customers. There are three primary requirements of these bills, and the CPUC is implementing these in multiple proceedings.*

| | | | |
|---|---|---|---|
| **Primary Requirements of bills** | **Distribution Planning Process Improvements (SB 410 & AB 50)** | **Energization Process and Timeline Improvements (SB 410 & AB 50)** | **Energization Cost Recovery Mechanism (SB 410)*** |
| Proceedings | **High DER Proceeding R.21-06-017** | **Energization OIR R.24-01-018** | **PG&E GRC Phase II A.21-06-021** |

*PG&E is the first utility to request a ratemaking mechanism under SB 410; other utilities may also do so in the future.

California Public
Utilities Commission

# Energization OIR High-level Scope

| Directives of SB 410 and AB 50 Addressed in OIR | |
|---|---|
| **Public Utilities Code Section** | **Description of Commission Directives** |
| 933.5(a)(1) and 934(a) | Establish:<br>• Criteria for timely service for customers to be energized<br>• Energization targets for different types of applicant service energization requests<br>• Procedure for customers to report energization delays to the Commission. |
| 933.5(a)(2), 933.5(d), 934(b), and 934(c) | Establish annual energization reporting requirements that reflect:<br>• Average, median, and standard deviation time to complete an energization request<br>• Explanation(s) for why select project(s) did not become energized within the required timeline<br>• Barriers that are impacting the IOUs ability to meet established timelines. |
| 933.5(a)(3) | Host an annual workshop to discuss the IOUs' efforts to accelerate their energization processes. |
| 933.5(b) | Establish public reporting requirements for IOUs that fail to demonstrate the ability to energize at least 65% of their projects each year within the adopted energization timing targets. |

# Process and Data to Complete Electric Rule 15 and 16 Energization Requests

- Matt Ventura, Senior Director – Service Planning & Design & Kevin Douty, Director – Strategy and Operations Support, Pacific Gas & Electric
- Brian Small, Senior Manager – Design Strategies & Performance, Southern California Edison
- Eric Turner, Project Manager – Developer Initiation, San Diego Gas & Electric

# PG&E New Business Service Connection Process

### Intake
- Collect detailed project scope info
- Identify customer needs
- Collect engineering advance

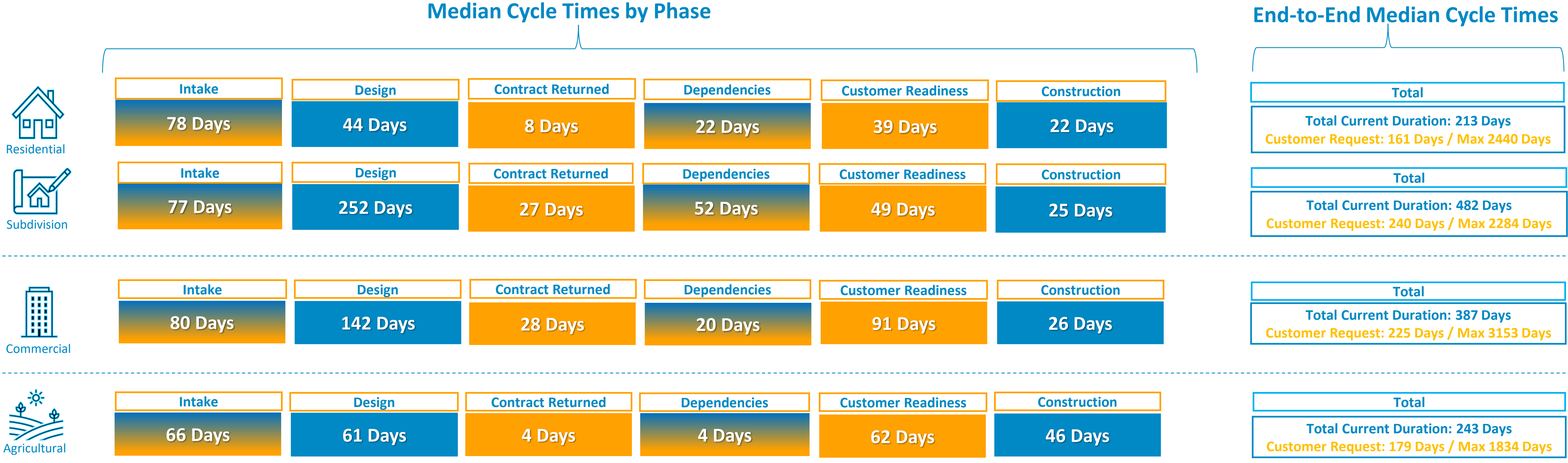
### Design
- Design service route & meter location
- Complete planning review
- Determine estimated cost of project

### Contract
- Customer signs, pays and returns contract

### Dependencies
- Receive needed permits, joint pole, easements and environmental reviews

### Customer Readiness
- Customer prepares their site for construction
- Customer passes all needed inspections

### Construction
- Coordinate site logistics
- Validate customer's site is construction-ready
- Perform service installation



## Median Cycle Times by Phase

## End-to-End Median Cycle Times

| | Intake | Design | Contract Returned | Dependencies | Customer Readiness | Construction | Total |
|---|---|---|---|---|---|---|---|
| Residential | 78 Days | 44 Days | 8 Days | 22 Days | 39 Days | 22 Days | Total Current Duration: 213 Days<br>Customer Request: 161 Days / Max 2440 Days |
| Subdivision | 77 Days | 252 Days | 27 Days | 52 Days | 49 Days | 25 Days | Total Current Duration: 482 Days<br>Customer Request: 240 Days / Max 2284 Days |
| Commercial | 80 Days | 142 Days | 28 Days | 20 Days | 91 Days | 26 Days | Total Current Duration: 387 Days<br>Customer Request: 225 Days / Max 3153 Days |
| Agricultural | 66 Days | 61 Days | 4 Days | 4 Days | 62 Days | 46 Days | Total Current Duration: 243 Days<br>Customer Request: 179 Days / Max 1834 Days |

PG&E Responsibility

Customer Responsibility

Joint Responsibility

*Median values used for all cycle time days

# PG&E New Business Service Connection Process

## Energization Timeline Recommendation

### Intake
- Collect detailed project scope info
- Identify customer needs
- Collect engineering advance

### Design
- Design service route & meter location
- Complete planning review
- Determine estimated cost of project

### Contract
- Customer signs, pays and returns contract

### Dependencies
- Receive needed permits, joint pole, easements and environmental reviews

### Customer Readiness
- Customer prepares their site for construction
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### Construction
- Coordinate site logistics
- Validate customer's site is construction-ready
- Perform service installation

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**Intake** | **Design** | **Contract Returned** | **Dependencies** | **Customer Readiness** | **Construction**

1

- Establish Design Cycle Time from Application Deemed Complete to Design Completed
- Set target using Median or % of work achieving Cycle Time target (i.e. 80%)

2

- Establish Construction Cycle Time from Customer Deemed Clear for construction to date of energization
- Set target using Median or % of work achieving Cycle Time target (i.e. 80%)

3 Establish Design and Construction targets by work type / segment

Residential

Subdivision

Commercial

Agricultural

Gaps to Solve:
- Applicant Design work
- Customer-driven redesigns
- Failed customer inspection impacts
- Customer maintaining site readiness

SDGE™

# ENERGIZATION TIMELINE WORKSHOP
## PANEL 1

Eric Turner | Project Manager – Developer Initiation

Friday, February 2nd, 2024

# HIGHLIGHTS

SDG&E is providing greater support and proactively forecasting with our customers.

Project types vary greatly with mixed utility/customer activities included in timelines.

Account for Regulations, Customer process, Easements and Authority Having Jurisdiction (AHJ) activities in timeline targets.

SDG&E recommends timeline targets based on IT System Constraints that support broad range of customers.

# CUSTOMER ENGAGEMENT

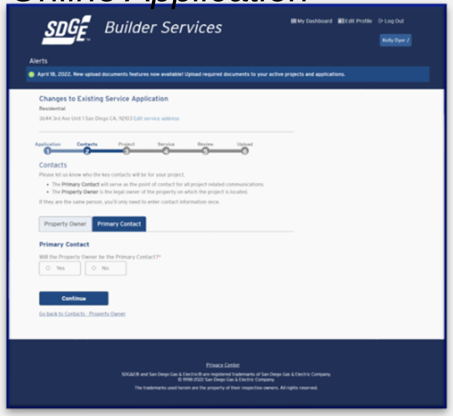
DEVELOPER INITIATION

BUILDER PORTAL

PROCESS AND TIMELINE

www.sdge.com/builder-services

*Online Application*


SDGE Builder Services

My Dashboard | Edit Profile | Log Out

Kelly Dyer

Alerts

April 18, 2022. New upload documents features now available! Upload required documents to your active projects and applications.

Changes to Existing Service Application

Residential

3644 3rd Ave Unit 1 San Diego CA, 92103 Edit service address

Application 1 · Contacts 2 · Project 3 · Service 4 · Review 5 · Upload 6

Contacts

Please let us know who the key contacts will be for your project.

- The **Primary Contact** will serve as the point of contact for all project related communications.
- The **Property Owner** is the legal owner of the property on which the project is located.

If they are the same person, you'll only need to enter contact information once.

Property Owner | Primary Contact

**Primary Contact**

Will the Property Owner be the Primary Contact?*

○ Yes ○ No

Continue

Go back to Contacts - Property Owner

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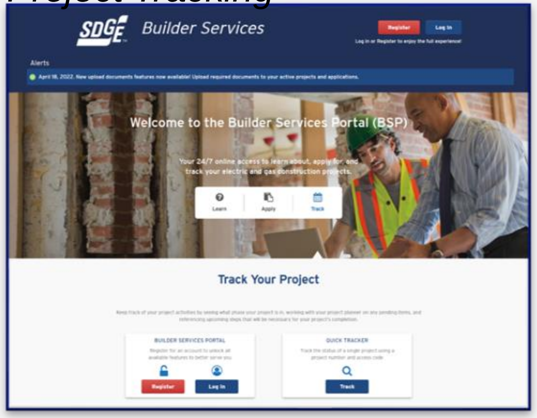
*Project Tracking*


SDGE Builder Services

Register | Log In

Log in or Register to enjoy the full experience!

Alerts

April 18, 2022. New upload documents features now available! Upload required documents to your active projects and applications.

Welcome to the Builder Services Portal (BSP)

Your 24/7 online access to learn about, apply for, and track your electric and gas construction projects.

Learn | Apply | Track

Track Your Project

Keep track of your project activities by seeing what phase your project is in, working with your project planner on any pending items, and referencing upcoming steps that will be necessary for your project's completion.

BUILDER SERVICES PORTAL

Register for an account to unlock all available features to better serve you.

Register | Log In

QUICK TRACKER

Track the status of a single project using a project number and access code.

Track

*Portal Guide*


SDG&E Builder Services Customer Portal

Quick-Start Guide

Logging In: Go to: http://www.sdge.com/builder-portal

The Portal Landing Page: When first accessing the landing page, you'll need to enter the Project or Job number and Access Code. You should've received your Access Code in your Welcome Package from SDG&E. Once information is entered, click the **Track Now** button.

Project Information: The Project page will display the following:
- Project start date
- Primary customer & phone number
- Phase the job is in
- Status details

Alert messages will display if pending information is required from the customer.

When the job is energized, phase boxes will not display and you'll see the word **Complete**.

Click the **Phase ?** to see details for each phase.

Review details for each job by clicking on the job number.

*Project Checklists*


SDGE A Sempra Energy utility

Checklist for Builders and Developers

ESTABLISHING NEW SDG&E® SERVICE ON LARGE-SCALE PROJECTS

Planning & Design

☐ Complete and submit the Service and Meter Request Form at sdge.com/service_meter_request. Upon receipt, SDG&E will contact you to discuss your project scope and requirements.

☐ Provide all required documentation and pay engineering fee requested by SDG&E.

☐ Review and approve proposed design(s) as required.

☐ Sign and return contract agreements, and pay project costs.

☐ Call SDG&E at 1-800-411-7343 to make billing arrangements/application.

Customer and Utility Construction

☐ Contact USA Dig Alert 48 hours prior to digging. Reach them at 8-1-1.

☐ Call Trench Desk to schedule pre-construction meeting with SDG&E staff (planner, project coordinator, inspector, etc.).

Trench Desk
- South of Hwy 56: 619-699-1039
- North of Hwy 56: 760-432-5805
- Orange County: 949-361-8061 (electric only)

☐ Call Trench Desk to schedule SDG&E inspections or reinspection after rain events for:
- Gas trench
- Electric conduit installation
- Service stubs
- Panel location
- Gas houseline(s)

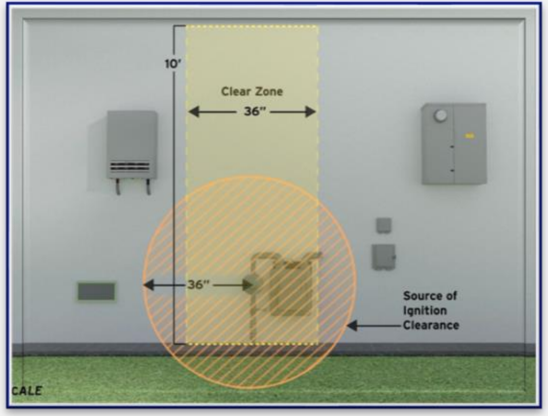
TIP • Obtain all necessary plan approvals and permits from appropriate local government agencies.

SDGE A Sempra Energy utility

Your Building Project

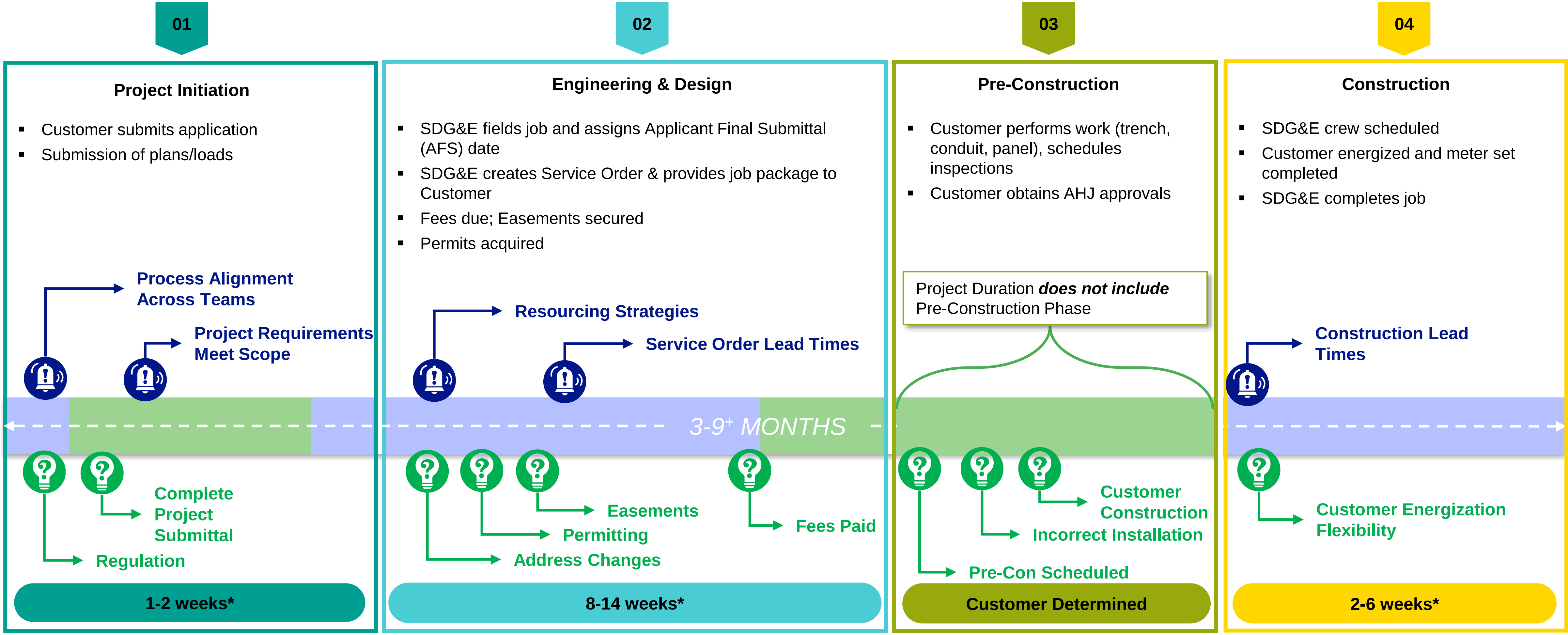
Checklist for Developers and Builders to establish new gas/electric service

*Standards Videos*



# SERVICE CONNECTION PROCESS: SMALL PROJECTS

*Typically Rule 16; Service Removals, Temp Power, Service Upgrades and Extensions, Disconnects/Reconnects*



**01**

**Project Initiation**

- Customer submits application
- Submission of plans/loads

**Process Alignment Across Teams**

**Project Requirements Meet Scope**

**Complete Project Submittal**

**Regulation**

**1-2 weeks***

**02**

**Engineering & Design**

- SDG&E fields job and assigns Applicant Final Submittal (AFS) date
- SDG&E creates Service Order & provides job package to Customer
- Fees due; Easements secured
- Permits acquired

**Resourcing Strategies**

**Service Order Lead Times**

**Easements**

**Permitting**

**Address Changes**

**Fees Paid**

**8-14 weeks***

*3-9$^+$ MONTHS*

**03**

**Pre-Construction**

- Customer performs work (trench, conduit, panel), schedules inspections
- Customer obtains AHJ approvals

Project Duration ***does not include*** Pre-Construction Phase

**Customer Construction**

**Incorrect Installation**

**Pre-Con Scheduled**

**Customer Determined**

**04**

**Construction**

- SDG&E crew scheduled
- Customer energized and meter set completed
- SDG&E completes job

**Construction Lead Times**

**Customer Energization Flexibility**

**2-6 weeks***

***Notes**

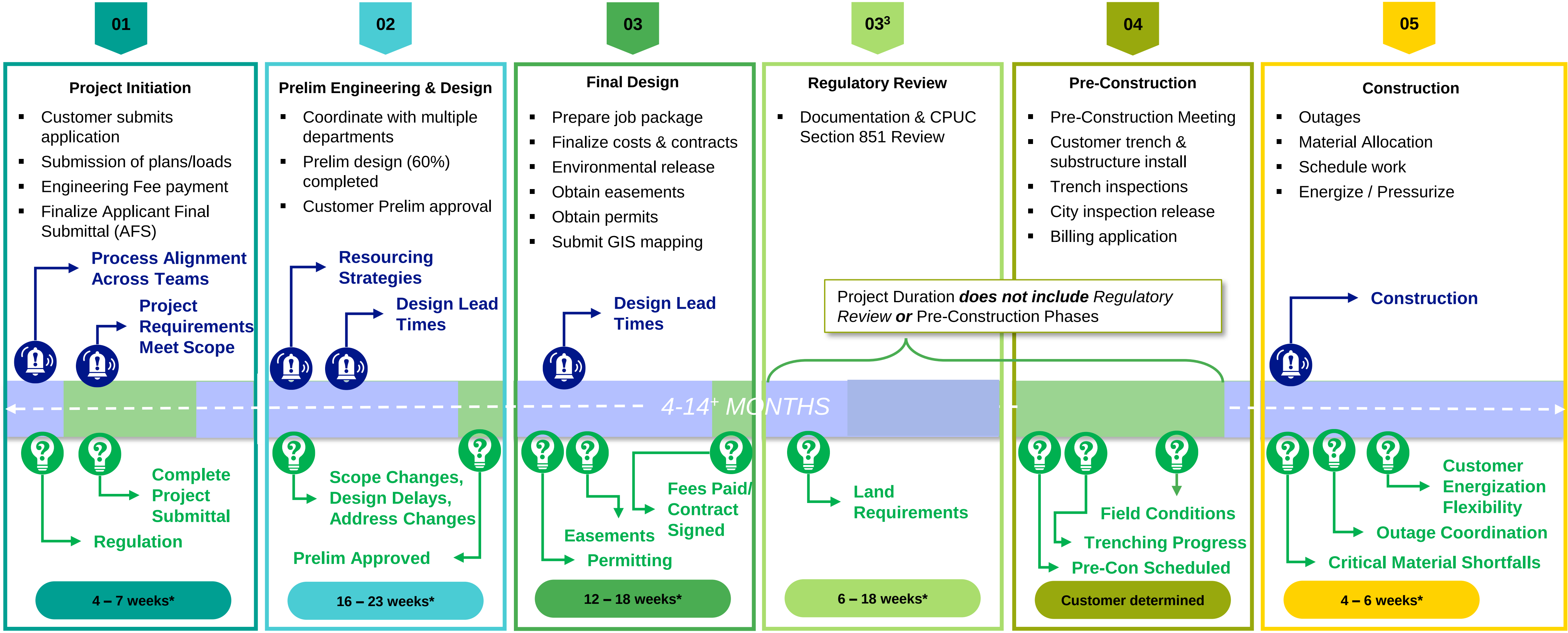
1. *Durations of project phases are estimates only; phase durations represent activities managed by SDG&E and do not include time for activities that are the responsibility of the customer/applicant.*

**WITHIN SDG&E CONTROL**

**OUTSIDE SDG&E CONTROL**

# SERVICE CONNECTION PROCESS: LARGE PROJECTS

*Rule 16 & 15; Convenience Store to High Rise, Single home to Large Subdivision, EV, Hospitals and Stadiums*



**01**

**Project Initiation**

- Customer submits application
- Submission of plans/loads
- Engineering Fee payment
- Finalize Applicant Final Submittal (AFS)

**4 – 7 weeks***

**02**

**Prelim Engineering & Design**

- Coordinate with multiple departments
- Prelim design (60%) completed
- Customer Prelim approval

**16 – 23 weeks***

**03**

**Final Design**

- Prepare job package
- Finalize costs & contracts
- Environmental release
- Obtain easements
- Obtain permits
- Submit GIS mapping

**12 – 18 weeks***

**03[3]**

**Regulatory Review**

- Documentation & CPUC Section 851 Review

Project Duration ***does not include*** *Regulatory Review* ***or*** Pre-Construction Phases

**6 – 18 weeks***

**04**

**Pre-Construction**

- Pre-Construction Meeting
- Customer trench & substructure install
- Trench inspections
- City inspection release
- Billing application

**Customer determined**

**05**

**Construction**

- Outages
- Material Allocation
- Schedule work
- Energize / Pressurize

**4 – 6 weeks***

***Notes***

1. *Timelines and activities in this graphic reflect those for complex projects (e.g., subdivisions, developments involving design by SDG&E). Requests that do not involve design by SDG&E (e.g., service work) tend to have shorter timelines and typically do not require approval from the California Public Utilities Commission (CPUC).*
2. *Durations of project phases are estimates only; phase durations represent activities managed by SDG&E and do not include time for activities that are the responsibility of the customer/applicant.*
3. *Not all projects require CPUC authorization and/or Regulatory Review. SDG&E will typically notify the customer of regulatory compliance obligations during Preliminary Engineering & Design.*

**WITHIN SDG&E CONTROL**

**OUTSIDE SDG&E CONTROL**

# FOCUS AND RECOMMENDATIONS

**ACCELERATION FOCUS**

- Process
    - Customer Collaborative Forecasting
- Resources
    - Satellite Planning Office
- Technology
    - Builder Portal Self-service

**RECOMMENDATIONS**

1. Streamline Municipal Permitting
    - Same Electrification Target as Utility
2. Utilize Current Reporting System Design
    - Reduce IT System upgrades
    - Minimize Resource Impacts/Project Delays
3. Establish Overall Timelines
    - Identify two streamlined and consistent timelines across project types
    - Tracking based on consistent job phases

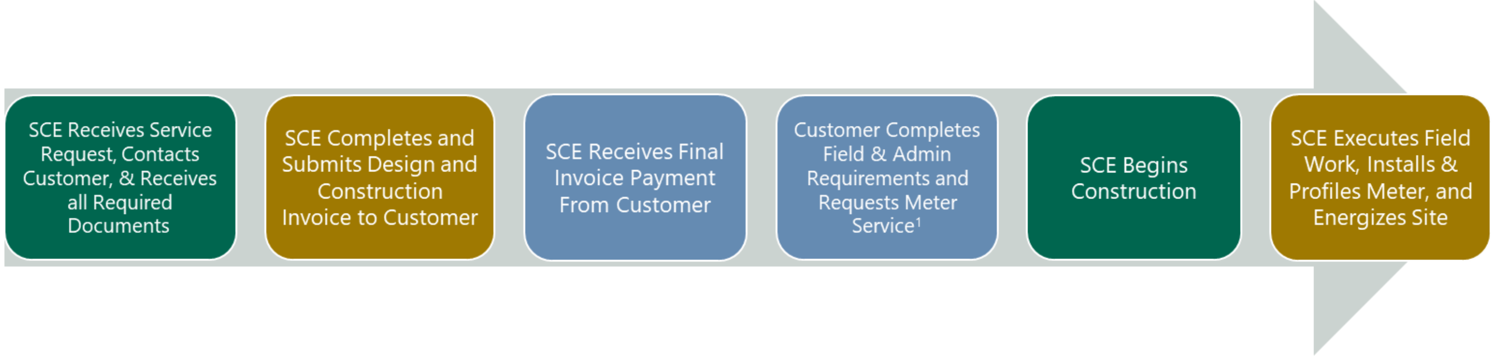
# Q&A

# Energization Workshop

Panel 1

February 2, 2024

# 2020-2023 New Service Requests: Line Extension / New Meter & Service cycle time from receipt of service request to site energization



SCE Receives Service Request, Contacts Customer, & Receives all Required Documents

SCE Completes and Submits Design and Construction Invoice to Customer

SCE Receives Final Invoice Payment From Customer

Customer Completes Field & Admin Requirements and Requests Meter Service[1]

SCE Begins Construction

SCE Executes Field Work, Installs & Profiles Meter, and Energizes Site

| **Average Cycle Time[1,2,3]** | **64** | **67** | **47** | **78** | **37** | **20** | **314** |
|---|---|---|---|---|---|---|---|
| Commercial | 68 | 84 | 52 | 102 | 44 | 24 | 374 |
| Residential | 63 | 58 | 44 | 65 | 33 | 18 | 281 |

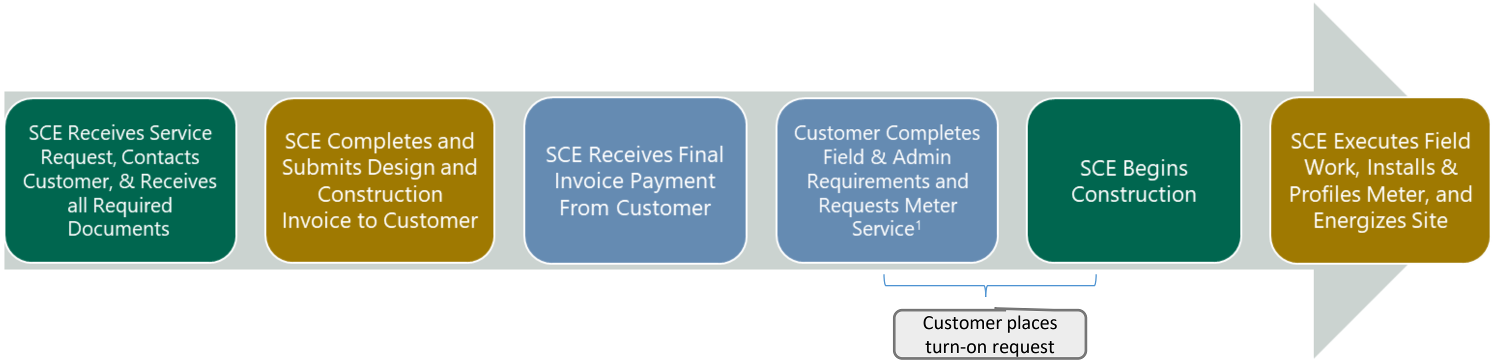
🟨 = SCE primarily responsible
🟦 = Customer primarily responsible
🟩 = Shared responsibility

[1] Represents 2020-2023 completed service requests that were created after 1/1/2017; estimated business days

[2] Sum of average stage durations may not sum to total duration due to overlap in steps

[3] Data excludes streetlight and meter-only projects, those not requiring billing, and projects outside of the service planning work group

# 2020-2023 New Service Requests: Rule 15 cycle time from receipt of service request to site energization

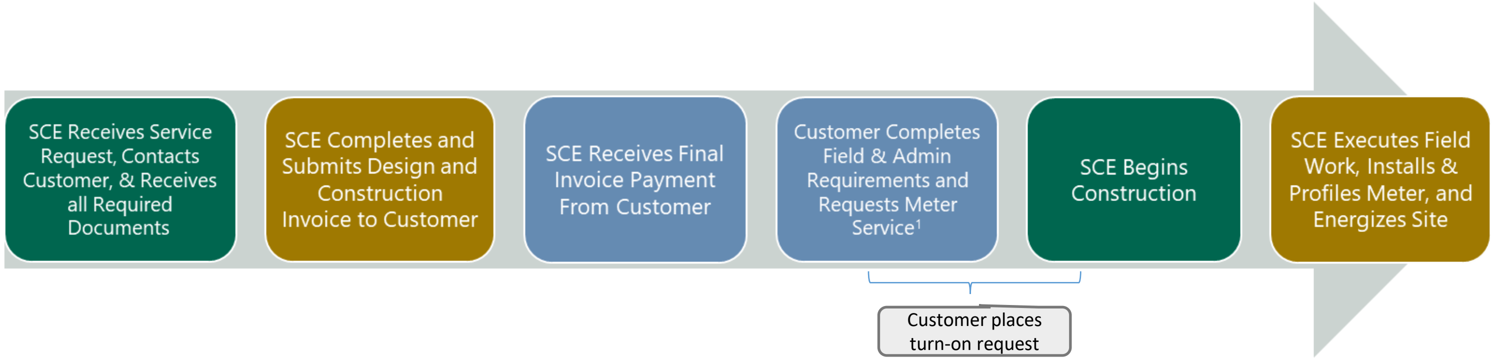


| **Average Cycle Time**[1,2,3] | **69** | **76** | **50** | **81** | **30** | **24** | **330** |
|---|---|---|---|---|---|---|---|
| Commercial | 74 | 99 | 56 | 108 | 33 | 32 | 401 |
| Residential | 66 | 65 | 47 | 68 | 29 | 21 | 296 |

🟫 = SCE primarily responsible
🟦 = Customer primarily responsible
🟩 = Shared responsibility

[1] 2020-2023 completed service requests created between 1/1/2017 and 12/31/2023; estimated business days
[2] Sum of avg. stage durations may not sum to total duration due to overlap in steps
[3] Data excludes streetlight and meter-only projects, those not requiring billing, and projects outside of the service planning work group

# 2020 - 2023 New Service Requests: Rule 16 cycle time from receipt of service request to site energization



SCE Receives Service Request, Contacts Customer, & Receives all Required Documents

SCE Completes and Submits Design and Construction Invoice to Customer

SCE Receives Final Invoice Payment From Customer

Customer Completes Field & Admin Requirements and Requests Meter Service[1]

SCE Begins Construction

SCE Executes Field Work, Installs & Profiles Meter, and Energizes Site

Customer places turn-on request

| **Average Cycle Time[1,2,3]** | **59** | **56** | **44** | **75** | **46** | **14** | **294** |
|---|---|---|---|---|---|---|---|
| Commercial | 60 | 69 | 49 | 96 | 56 | 16 | 345 |
| Residential | 58 | 48 | 40 | 62 | 39 | 14 | 262 |

🟫 = SCE primarily responsible
🟦 = Customer primarily responsible
🟩 = Shared responsibility

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[1] 2020-2023 completed service requests created between 1/1/2017 and 12/31/2023; estimated business days
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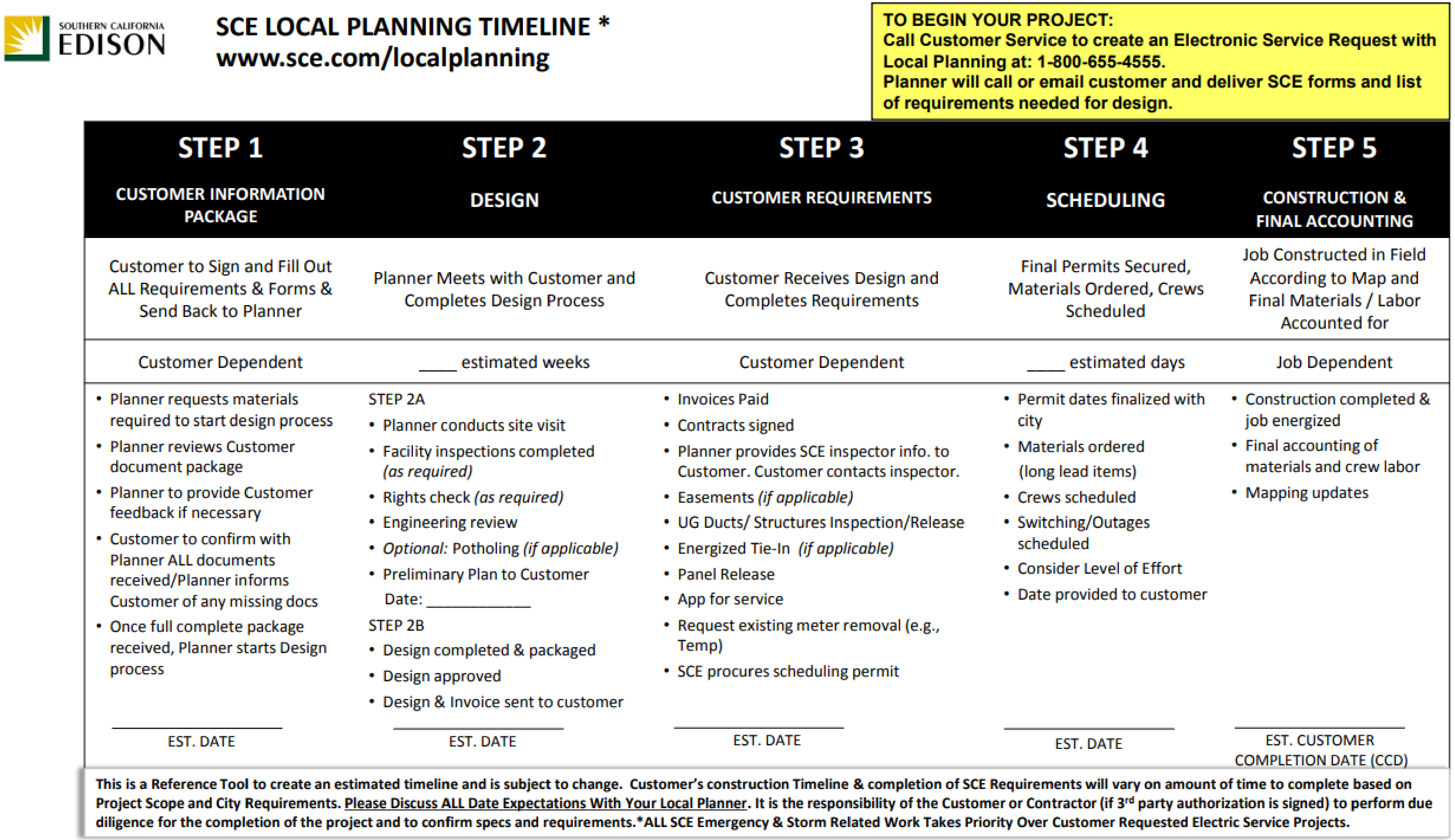


# SCE LOCAL PLANNING TIMELINE *
www.sce.com/localplanning

**TO BEGIN YOUR PROJECT:**
**Call Customer Service to create an Electronic Service Request with Local Planning at: 1-800-655-4555.**
**Planner will call or email customer and deliver SCE forms and list of requirements needed for design.**

| **STEP 1**<br>**CUSTOMER INFORMATION PACKAGE** | **STEP 2**<br>**DESIGN** | **STEP 3**<br>**CUSTOMER REQUIREMENTS** | **STEP 4**<br>**SCHEDULING** | **STEP 5**<br>**CONSTRUCTION & FINAL ACCOUNTING** |
|---|---|---|---|---|
| Customer to Sign and Fill Out ALL Requirements & Forms & Send Back to Planner | Planner Meets with Customer and Completes Design Process | Customer Receives Design and Completes Requirements | Final Permits Secured, Materials Ordered, Crews Scheduled | Job Constructed in Field According to Map and Final Materials / Labor Accounted for |
| Customer Dependent | ____ estimated weeks | Customer Dependent | ____ estimated days | Job Dependent |
| • Planner requests materials required to start design process<br>• Planner reviews Customer document package<br>• Planner to provide Customer feedback if necessary<br>• Customer to confirm with Planner ALL documents received/Planner informs Customer of any missing docs<br>• Once full complete package received, Planner starts Design process | STEP 2A<br>• Planner conducts site visit<br>• Facility inspections completed *(as required)*<br>• Rights check *(as required)*<br>• Engineering review<br>• *Optional:* Potholing *(if applicable)*<br>• Preliminary Plan to Customer Date: ___________<br>STEP 2B<br>• Design completed & packaged<br>• Design approved<br>• Design & Invoice sent to customer | • Invoices Paid<br>• Contracts signed<br>• Planner provides SCE inspector info. to Customer. Customer contacts inspector.<br>• Easements *(if applicable)*<br>• UG Ducts/ Structures Inspection/Release<br>• Energized Tie-In *(if applicable)*<br>• Panel Release<br>• App for service<br>• Request existing meter removal (e.g., Temp)<br>• SCE procures scheduling permit | • Permit dates finalized with city<br>• Materials ordered (long lead items)<br>• Crews scheduled<br>• Switching/Outages scheduled<br>• Consider Level of Effort<br>• Date provided to customer | • Construction completed & job energized<br>• Final accounting of materials and crew labor<br>• Mapping updates |
| ________________<br>EST. DATE | ________________<br>EST. DATE | ________________<br>EST. DATE | ________________<br>EST. DATE | ________________<br>EST. CUSTOMER COMPLETION DATE (CCD) |

**This is a Reference Tool to create an estimated timeline and is subject to change. Customer's construction Timeline & completion of SCE Requirements will vary on amount of time to complete based on Project Scope and City Requirements. <u>Please Discuss ALL Date Expectations With Your Local Planner</u>. It is the responsibility of the Customer or Contractor (if 3rd party authorization is signed) to perform due diligence for the completion of the project and to confirm specs and requirements.*ALL SCE Emergency & Storm Related Work Takes Priority Over Customer Requested Electric Service Projects.**

# Key Take Aways

- End to end cycle timelines are very difficult to determine due to various tasks out of SCE control.
  - Work that a customer is responsible for
  - Invoices/Contracts
  - Easements
  - Permits
  - AHJ release

- Timeframes around SCE responsible tasks such as design time, and electrical construction time averages can be determined based on project size and complexity.
  - R15 vs. R16
  - Commercial vs. Residential
  - Panel size dictates the number of ducts and structures
  - Amount of load to be added can determine the level of effort needed for both design and electrical construction

- SCE is currently working on new technology to improve the customer experience.
  - Common Intake Portal
  - Various system upgrades

# 10-Minute Break

# Process and Data to Complete Investments for Upstream Distribution Capacity Projects

- Bill Peters, Manager – Electric Planning Policy & Moderation & Jennifer Goncalves – Principal Grid Innovation Engineer, Pacific Gas & Electric
- Roger Salas, Principal Manager - Distribution System Analysis, Southern California Edison
- Yi Li, Distribution Planning Policy Manager, San Diego Gas & Electric

# Energization Workshop

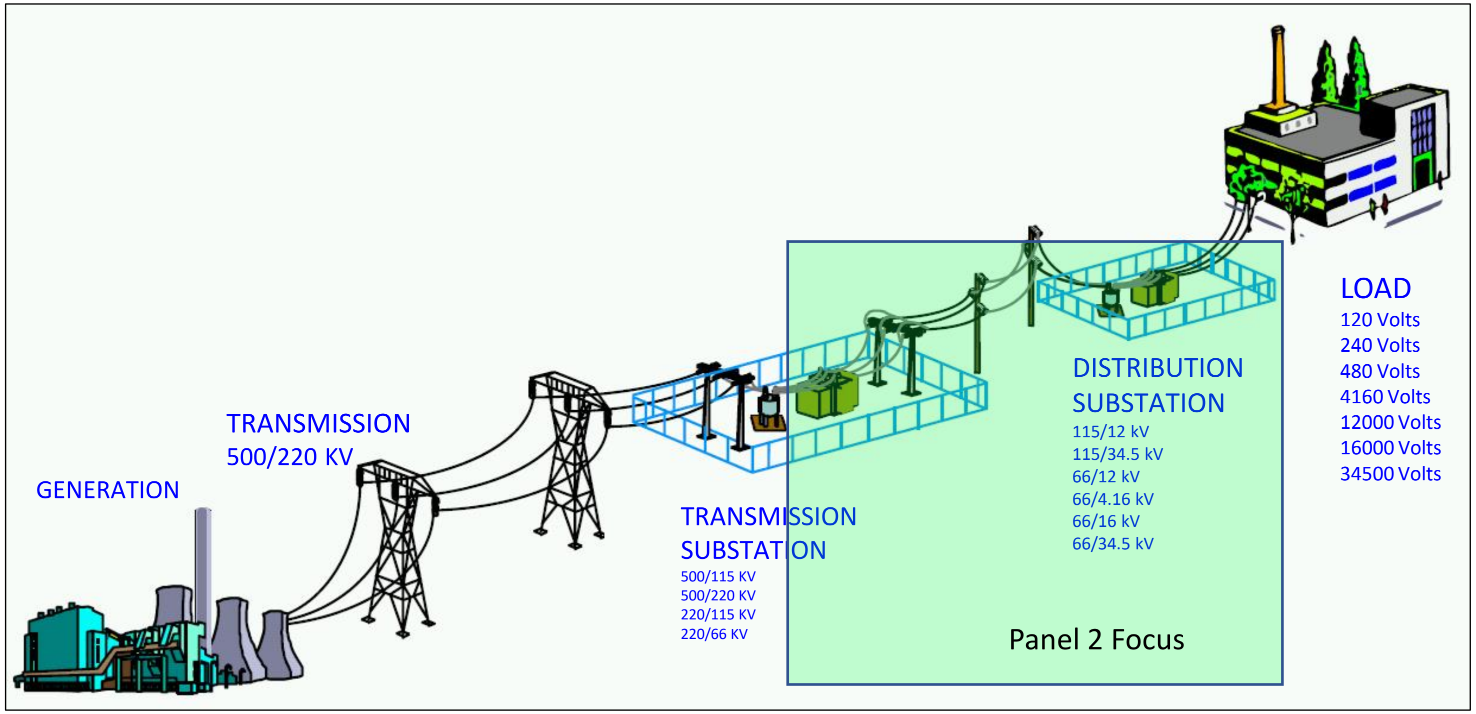
Panel 2

February 2, 2024

# Typical Distribution Capacity Upgrades, Scope, Timing

1.5-10 years for grid upgrades depending on type and scope

**Objective:** Provide information on process, timeline and complexities for completing grid upgrades necessary for service energization



# Typical Distribution Capacity Upgrades, Scope, Timing

*1.5-10+ years for grid upgrades depending on type and scope*

**Caveats:** Each distribution system upgrade is unique, with different challenges. The timelines indicated below are "typical" timelines from when projects are funded and approved and are not a guaranteed.

### Distribution Circuit Capacity Upgrades (Estimated Timeline: 18-24 Months)

- Replace low-capacity cable/conductor with high-capacity cable/conductor (such replace 1/0 ACSR with 336 ACSR)
- Upgrade existing underground substation getaways to reduce heating (such separate a ductbank with 5 circuit with two ductbanks of 3 and 2 circuits, new blister at the substation, double-runs)
- Install distribution system equipment such as voltage regulator, switches, and automation devices
- Line extension to offload circuit to adjacent circuit
- Voltage conversion (Cutover) from lower voltage (such 4kV) to higher voltage (such as 12kV)

### Install New Distribution Circuits(Estimated Timeline: 36 Months +/- 6 months)

- Install a new line position breaker inside the substation
- Route new wire/conductor from inside the substation to specific location
- Perform necessary switching operations to reconfigure system
- Substation rack extension

### Increase Capacity at Existing Substation(Estimated Timeline: 3-4 Years)

- Add new transformer bank (such as new 28MVA)
- Replaced low-capacity transformer with higher capacity transformer (such as replace 22.5MVA with 28MVA unit)
- Replace low-capacity equipment with higher capacity equipment (such as for bus, breaker, conductor, disconnects

### Installation of New Substation in Green Field (Estimated Timeline: 7-10 Years)

- Find acceptable location that meets electrical needs
- Typically, will requires licensing

### Upgrade an existing high voltage(>50kV) line (Estimated Timeline: 3-5 Years)

- For lines not under CAISO jurisdiction
    - Example: Replace 336A with 954SAC

### Install new high voltage(>50kV) lines (Estimated Timeline: 5-7 Years)

- Find acceptable pathway to meet electrical needs
- Typically, will requires licensing

# Process for Completing Upstream Distribution Capacity Projects

## *High Level Process Steps*

1) Project Identification
    a) Typically Identified as part of the Annual Distribution Planning Process(DPP)
    b) In Some cases, project needs are identified as part of new Load Studies required by new load requests (coordinate with annual DPP)
2) Project specification developed
    a) Scope, Cost, Alternatives, Timelines
3) Approve the project
    a) Funding
    b) Resources
    c) Timelines
4) Licensing activities for those projects requiring licensing evaluation
5) Project management
    a) Design
    b) Permitting
    c) Environmental
    d) Procurement
    e) Construction
    f) In-service

# Related to Grid Capacity Upgrades Influencing Constraints

## In SCE Control

- Determination that a grid upgrade is needed and related scope
  - Distribution Planning Process
  - Engineering Capacity Studies
- Project timelines execution in coordination with other SCE work*
  - Design, permitting, construction
- SCE Preliminary & Final Design Timelines*
- SCE Construction & Energization Timelines*
- * Often impacted by “out of SCE control activities”

## Out of SCE Control (not inclusive)

- Easements needed for new line route/equipment location
- Local (City) permitting
- Permits from other entities (railroad, Cal Trans, Forestry, Coastal Commission, Native American Land, Aviation, etc.)
- PUC Licensing requirements
- Material challenges (global supply)
- Municipality hold ups (Moratoriums)
- Emergency work
- Customer project phasing

# Accelerating Energization Timing Through Technology, Tools, and Advanced Planning

*Related to activities with SCE control or influence*

The following are activities SCE is pursuing to accelerate energization timelines

- Utilization of Load Management via SCE's Load Control Management System (LCMS) pilot
  - Allows customer to use load control system while grid upgrades are completed
- Improved load forecasting tools / methodologies to better predict when and where system upgrades may be required to better align with customer needs
- External engagement– encouraging customers to approach SCE early in their planning process to ensure the grid is ready.
  - Including townhall meetings and community forums
- Improvements to planning
  - ▪ Evaluate multiple demand scenarios to prepare the grid for likely scenarios

# Recommendations for Improvements

## *Related to Grid Capacity Upgrades (related to outside SCE Control)*

The following are areas where SCE recommends improvements

- Ability to obtain blanket permits (cities, counties, governmental land) or expedite the local permitting/approval process
- Grant a GO 131 Exemption for Energy Projects < 150 kV
- Expedite CPUC Licensing approval process
- Improve coordination with multiple agencies for faster permitting process (railroad, Cal Trans, etc.)

# Energization Workshop

## Panel 2

## Distribution Capacity Upgrades

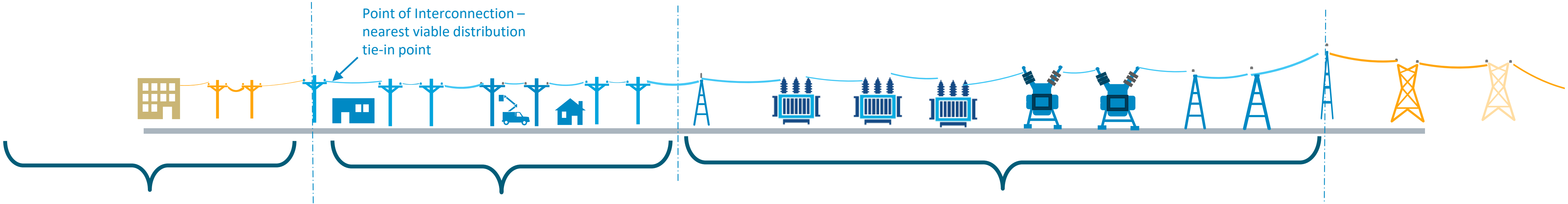
February 2nd, 2024

# Key Messages

PG&E believes the intention of SB 410 is to implement energization timelines for New Business projects; however, establishing a timeline for projects that trigger upstream capacity upgrades will be highly variable and dependent upon a variety of other factors

- The majority of requests to energize customer loads do not require upstream capacity upgrades to the distribution system
- Upstream capacity projects are complex and each is unique, and they are dependent on a number of internal and external requirements
- The CPUC is exploring multiple process improvements to improve Distribution Planning in the High DER Proceeding
- PG&E is also implementing process improvements for identification and completion of capacity upgrades
- Ratepayer impacts should be considered when considering capacity upgrades

# Typical Types of Upstream Distribution Capacity Upgrades



**Service Interconnection Facilities**

**Service Interconnection Facilities**

**To be discussed in Panel 1**

**Distribution Line Upgrades:**

**Work can include:**

- **Reconductoring overhead or underground line**
- **Installing new overhead or underground line with any needed new line equipment**
- **Installing voltage regulation**
- **Installing capacitor banks**
- **Conversion to higher voltage**
- **Installing circuit ties to reconfigure system**

**Distribution Substation Upgrades:**

**Work can include:**

- **New substations**
- **New transformers**
- **Replacement transformers**
- **New circuit breakers**
- **Bus reconductoring**
- **New control buildings**
- **New battery buildings**
- **Expanded or replacement fencing**
- **Addition or replacement of SCADA communication systems**

**Related "Transmission" Upgrades at Distribution Substations:**

**Work can include:**

- **New transmission breakers**
- **Replacement of transmission fuses or switches with breakers**
- **Reconfiguration of existing transmission protection scheme to BAAH or Ring Bus**
- **Addition or replacement of SCADA**
- **Protection scheme changes at other substations**

**Transmission Line Facilities**

# Distribution Capacity Upgrades - Process

## Process

1) Capacity Assessment and Project Identification
   - > When a new application is received, assess whether the new load creates an overload using hourly load profiles of both existing facilities and new load
   - > Different customers will have different load profiles and will impact the grid differently
   - > Assess whether mitigation may allow some load to interconnect, like load flexibility
   - > If a project is needed, the scope of project is based on a longer term view of growth
2) Funding and prioritization
   - > The General Rate Case (GRC) provides authorized amounts for capacity every 4 years*
   - > Three tiers for prioritization (ongoing work, customer-driven work, organic growth)**
3) Design and Estimating
4) Permitting (if applicable)
5) Sourcing of Materials
6) Construction, Testing, and Delivery

*PG&E has also requested a balancing account in the 2023 GRC Part 2 of Phase 1

**Responses to Amended Scoping Memo, Appendix A, High DER Proceeding, PG&E, Sept 13th, pages 15-16

# Schedule Variability: Distribution Line Capacity Upgrades

## Timelines for Upgrades (Contingent on Funding Availability)

Distribution Line Upgrades: 2-4 years after funding available, if no delays

**Schedule variability causes within PG&E's control:**

- Estimating and/or construction resources reallocated to emergency or response work

**Additional variability partly outside of PG&E's control*:**

- Permit requirements (Caltrans, Railroad, environmental, water discharge, forestry, city, county, ADA curb, Coastal Commission, etc.)
- Right-of-way and easement acquisition
- Field conditions different than design
- Local working hour restrictions
- Weather/access conditions
- Limited clearance timeframe
- Equipment failure prevents clearances
- Cost escalations require additional funding not available in current year

*RESPONSES TO AMENDED SCOPING MEMO APPENDIX A BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), Sept 13th, pages 17-18

# Schedule Variability: Substation Capacity Upgrades

## Timelines for Upgrades (Contingent on Funding Availability)

Substation Upgrades: 4-6 years after funding available, without any delays

**Schedule variability causes within PG&E's control:**

- Estimating and/or construction resources reallocated to emergency or response work

**Additional variability partly outside of PG&E's control*:**

- 3 years for substation transformers
- 4 years for transmission breakers
- CPUC/CEQA permit for new substations and substation expansions (up to 10 years)
- Limited clearance timeframe (up to 12 months if clearance window missed)
- Equipment failure prevents clearance until equipment is repaired or replaced
- Cost escalations require additional funding not available in current year

*RESPONSES TO AMENDED SCOPING MEMO APPENDIX A BY PACIFIC GAS AND ELECTRIC COMPANY (U 39 E), Sept 13th, pages 17-18

# Distribution Capacity Upgrades – Improvements

- **Ongoing Activities and Recommendations:**
  - Leverage PG&E's Regional Service Model and Community Engagement to interface with customers and customer groups to understand where growth is likely to occur*
  - Explore ways in which customers can self-fund projects. This would allow PG&E to accelerate projects that would not otherwise be funded under the current year budget.
  - Seek access to additional funding to accelerate capacity upgrades for energization, including non-traditional funding sources (e.g., PG&E’s proposed LCFS Pilot, the Department of Energy’s Grid Innovation and Resilience Program and other federal grants) to fund capacity and resilience projects in partnership with customers and communities
  - Plan our electric capital work across multiple objectives – reducing wildfire risk, adding capacity, improving asset health, and improving reliability – and seek opportunities to address multiple needs with a single solution
  - Create more detailed project designs to provide agency permit desks with required information and avoid redesign and delays while working with agencies to streamline permitting processes
  - Explore the use of load flexibility to allow some load to energize sooner

* Reply Comments by PG&E on Responses to the April 6, 2023 Ruling, High DER Proceeding, Page 2.

# Energization Timeline Workshop – Panel 2

Yi Li | Distribution Planning Policy Manager

Friday, February 2, 2024

# Highlights

SDG&E managed over 10,000 jobs annually to connect customer loads in the last 5 years. Approximately 0.1% required upgrades to SDG&E's distribution system.

Timelines for upstream capacity projects vary greatly, from 1 – 15 years.  It is not practical to develop a timeline target for upgrades with this degree of variation.

Meeting customer energization needs has limited dependency on the timeline for upstream capacity projects. SDG&E has always been able to meet customer needs; in some cases those needs are phased which allows time to add distribution capacity.

SDG&E recommends excluding from the timeline targets, load requests that trigger upstream capacity projects.

# Types of Distribution Capacity Upgrade Projects

- Utilization of existing system capacity is considered prior to initiating backbone capacity upgrades
- The steps and timeline for completing a particular upgrade vary widely depending on the specific characteristics and requirements associated with the upgrade

New or upgraded circuit

*One to three years*

Replacement of an existing substation transformer

*Three to five years*

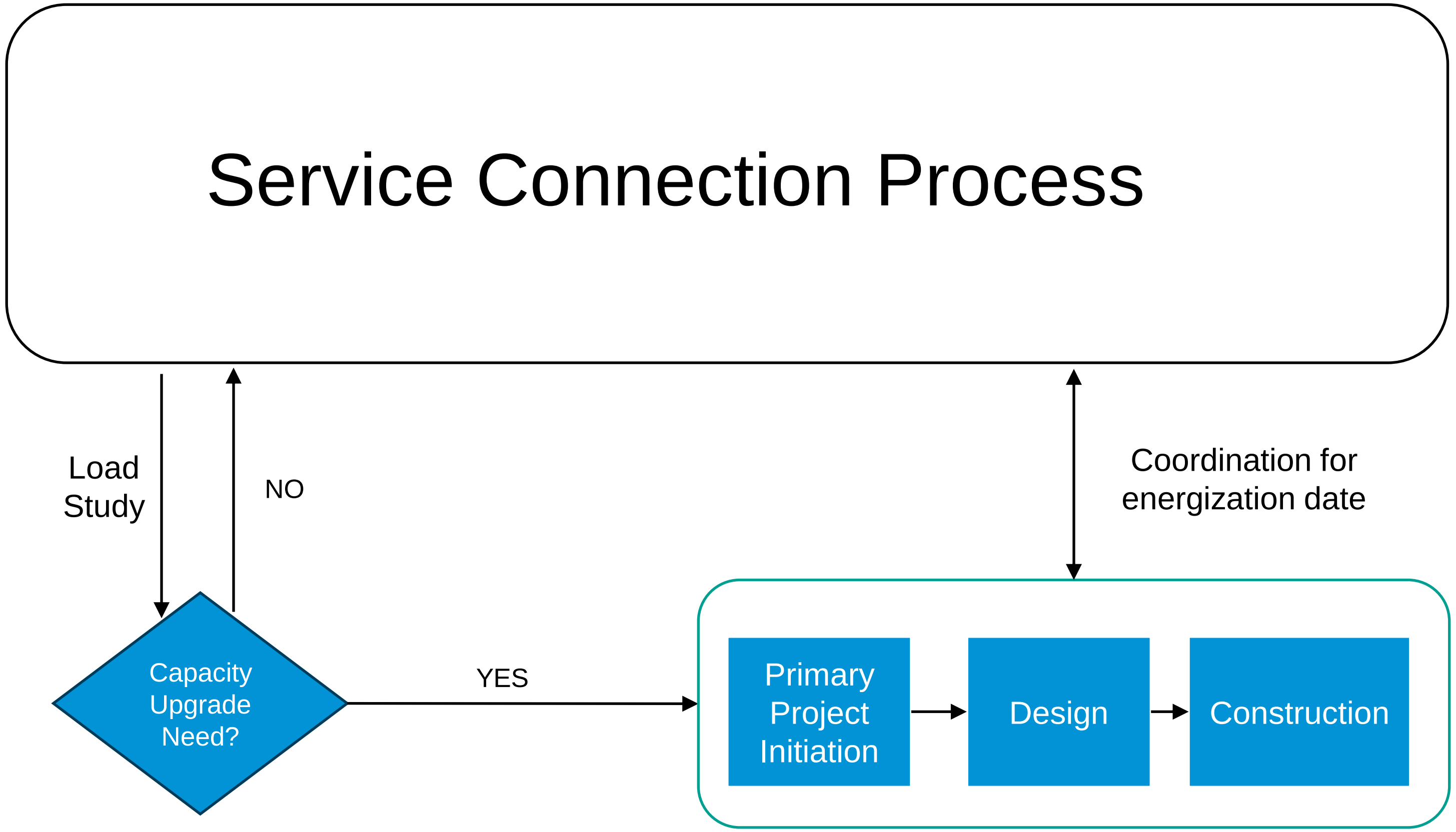
Addition of a new substation transformer within an existing substation

*Three to five years*

New substation

*Five to fifteen years*

# Customer Needs Triggered Capacity Projects



Service Connection Process

Load Study

NO

Coordination for energization date

Capacity Upgrade Need?

YES

Primary Project Initiation

Design

Construction

# Capacity Project Example

### Customer Service Request

**Details:**

- ✓ 8MW Load Request
- ✓ Requests Energization by 2020

### Customer Clarification

**Details:**

- ✓ Customer only requires 2MW initially
- ✓ Load will materialize over time

### Engineering Review

**Details:**

- ✓ Capacity available for 2MW
- ✓ Grid need Identified for remaining load
- ✓ New 12kV Circuit Initiated
- ✓ In-service date of 2022

### Capacity Upgrade

**Details:**

- ✓ New Circuit Energized
- ✓ Full 8MW of load can now be served

# Key Elements for Success

Early engagement between customers and the utility

Streamlined permitting for infrastructure development

Streamlined distribution planning process

# LUNCH

- We will start the afternoon session at 1:00pm

# Panel – Customer Experience Requesting New and Upgraded Service from the Utility – Part 1

- Corey Smith, Executive Director, Housing Action Coalition
- Chris Shimoda, Senior Vice President of Government Affairs, California Trucking Association
- Aravind Kailas, Advanced Technology Policy Director, Volvo Group North America

HOUSING
ACTION
COALITION

# HAC's Unique Perspective

**Home-Building Industry**

- Share timely updates and intel
- Advocate for housing projects
- Facilitate cross-sector networking

**As a grass-tops leader, HAC uniquely connects all three stakeholders**

**Voters/General Public**

- Organize + activate pro-housing neighbors
- Convene educational forums
- Connect constituents with decision-makers

**Government**

- Inform policy
- Sponsor and support legislation
- Be a pro-housing voice in the room

HOUSING
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# Housing is an equity issue

HOUSING
ACTION
COALITION

# How we got involved in this issue

- IOUs/Utility Companies cause delays “on every single project” in Northern California and on a significant number of projects outside PG&E territory.
- Areas of delay:
    - Preparation of plans
    - Conflicting facilities
    - Review process
    - Disconnecting power and gas
    - Temporary power
    - Dirt work
    - Final Interconnection, last step and focus of Senate Bill 83 (Wiener)

# Interconnection delays

- Due to a number of factors, mainly lack of bandwidth for the IOUs.
    - There is work the IOUs were previously outsourcing to other unions but have recently stopped that practice.
- Work is ‘fee for service’, meaning projects are paying for this work to be completed in a timely fashion.
- Has always been bad, and started getting even worse 10 years ago.

# Some of the challenges…

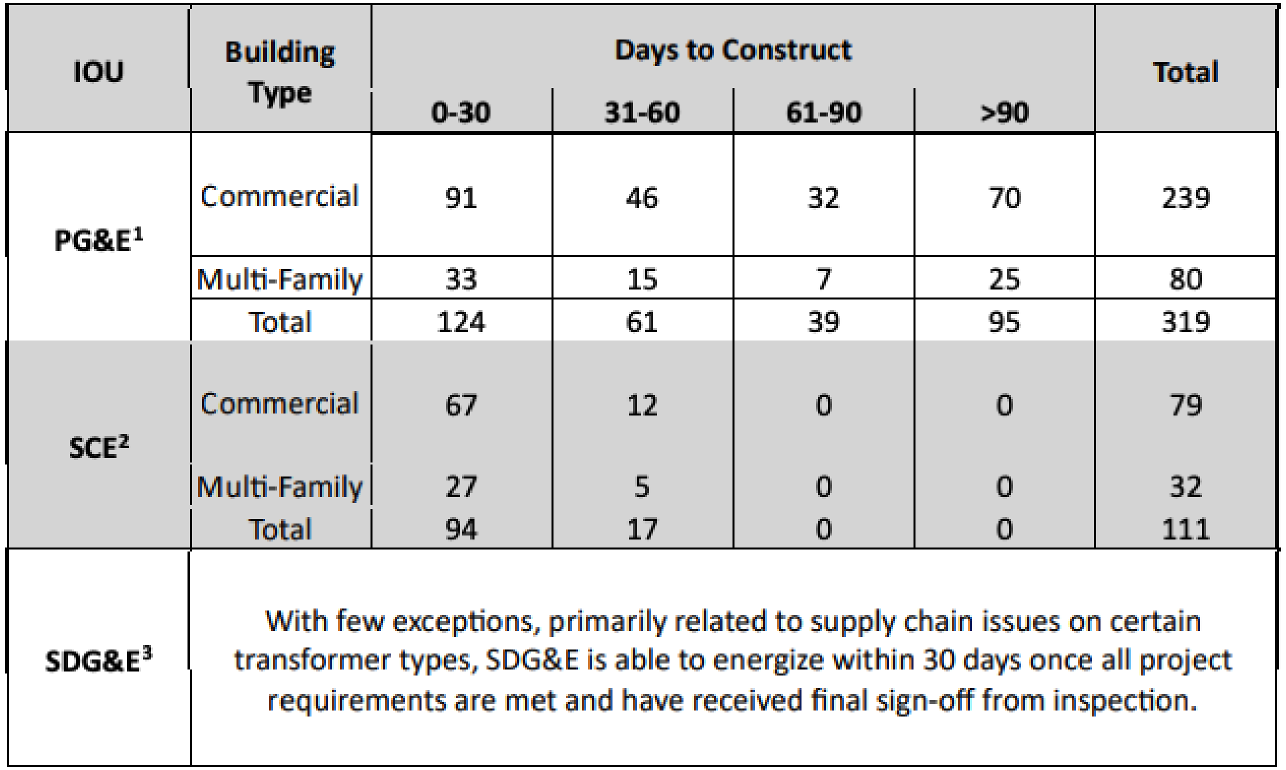
- Supply chain issues (transformer delays 1-2 years per PG&E)
- Communication between project sponsor, utility companies, and local jurisdictions
    - Projects try to ‘time’ a broken system
    - IOUs have not show up to appointments
    - Misalignment between city and utility company requirements

# Impact on housing construction

- These delays create a negative impact on housing production in a variety of ways
    - New housing (affordable and mixed income) that is complete but not able to open
    - Increasing cost of new housing
        - Carrying cost of the delay
        - Increased risk associated with not getting hookups impacts lending

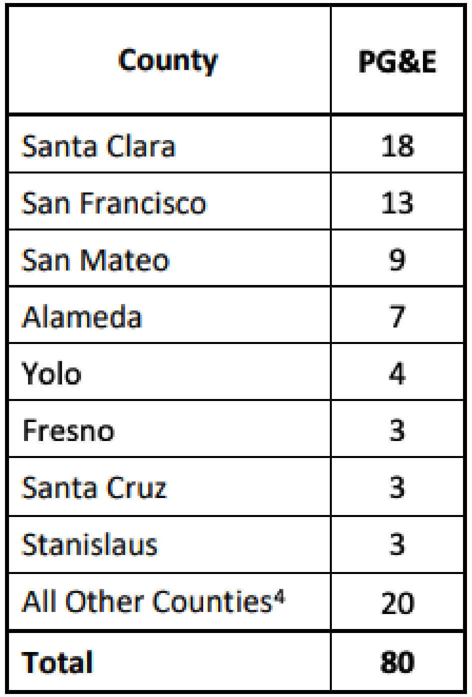
# Data - Queue Feb. 2023

*Table 1 - Green Tagged New Construction Project Queue Summary*



| **IOU** | **Building Type** | **Days to Construct** | | | | **Total** |
|---|---|---|---|---|---|---|
| | | **0-30** | **31-60** | **61-90** | **>90** | |
| **PG&E**[1] | Commercial | 91 | 46 | 32 | 70 | 239 |
| | Multi-Family | 33 | 15 | 7 | 25 | 80 |
| | Total | 124 | 61 | 39 | 95 | 319 |
| **SCE**[2] | Commercial | 67 | 12 | 0 | 0 | 79 |
| | Multi-Family | 27 | 5 | 0 | 0 | 32 |
| | Total | 94 | 17 | 0 | 0 | 111 |
| **SDG&E**[3] | With few exceptions, primarily related to supply chain issues on certain transformer types, SDG&E is able to energize within 30 days once all project requirements are met and have received final sign-off from inspection. | | | | | |

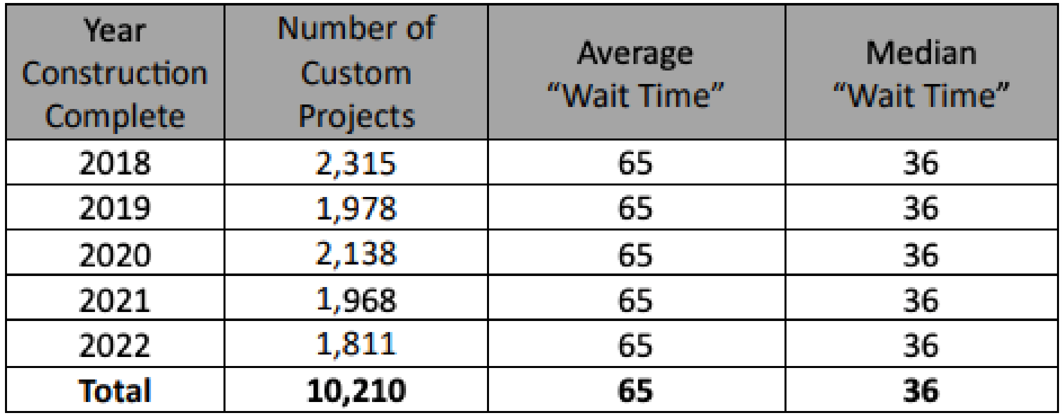
*Table 2a - PG&E Green Tagged Multi-family New Construction Project Locations*



| **County** | **PG&E** |
|---|---|
| Santa Clara | 18 |
| San Francisco | 13 |
| San Mateo | 9 |
| Alameda | 7 |
| Yolo | 4 |
| Fresno | 3 |
| Santa Cruz | 3 |
| Stanislaus | 3 |
| All Other Counties[4] | 20 |
| **Total** | **80** |

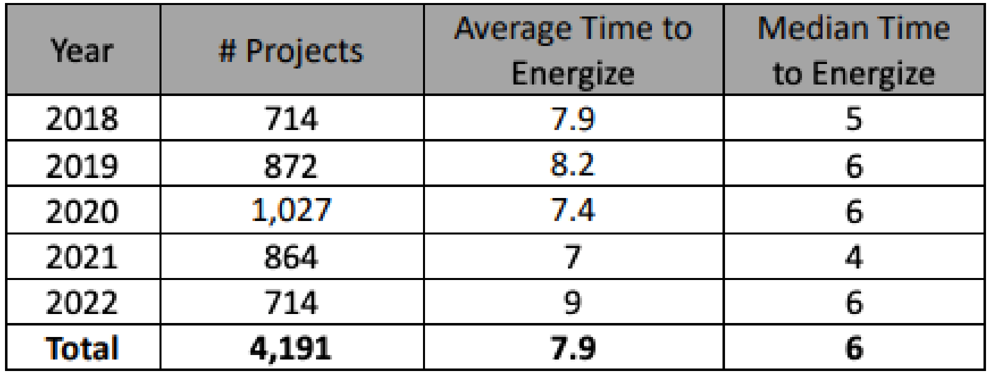
# Historical Data from IOUs

*Table 3 - PG&E Average and Median Wait Times to Energize (Calendar Days)*



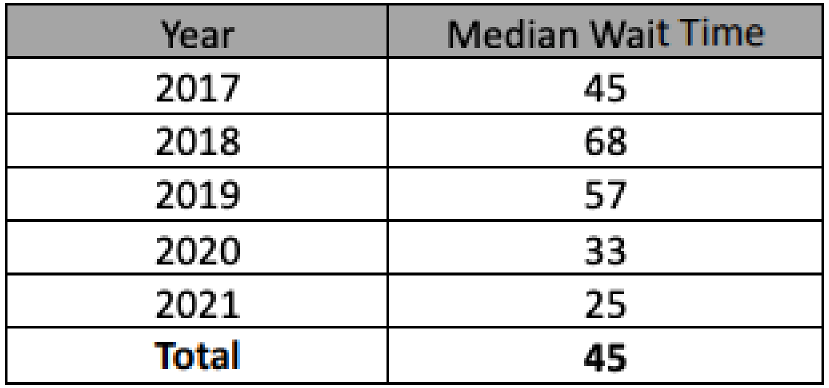
| Year Construction Complete | Number of Custom Projects | Average "Wait Time" | Median "Wait Time" |
|---|---|---|---|
| 2018 | 2,315 | 65 | 36 |
| 2019 | 1,978 | 65 | 36 |
| 2020 | 2,138 | 65 | 36 |
| 2021 | 1,968 | 65 | 36 |
| 2022 | 1,811 | 65 | 36 |
| **Total** | **10,210** | **65** | **36** |

*Table 4 – SCE Average and Median Wait Times to Energize Multi-Family (Business Days)*



| Year | # Projects | Average Time to Energize | Median Time to Energize |
|---|---|---|---|
| 2018 | 714 | 7.9 | 5 |
| 2019 | 872 | 8.2 | 6 |
| 2020 | 1,027 | 7.4 | 6 |
| 2021 | 864 | 7 | 4 |
| 2022 | 714 | 9 | 6 |
| **Total** | **4,191** | **7.9** | **6** |

*Table 5 – SDG&E Median Wait Times to Energize (Work Days)*



| Year | Median Wait Time |
|---|---|
| 2017 | 45 |
| 2018 | 68 |
| 2019 | 57 |
| 2020 | 33 |
| 2021 | 25 |
| **Total** | **45** |

# PG&E press coverage

POLITICS

## Big holdup for new Northern California housing? PG&E

**Dustin Gardiner, Julie Johnson**

March 10, 2023 | Updated: March 10, 2023 11:57 a.m.

26 DECEMBER 2023 / SF NEWS / JOE KUKURA

## The Latest Barrier to New Bay Area Housing? PG&E Equipment Delays

OPINION // EDITORIALS

## If PG&E can't turn the lights on for new housing, California needs to step in

California is tasked with building 2.5 million homes in the next eight years. Unnecessary delays from PG&E are slowing us down.

**Chronicle Editorial Board**

April 23, 2023 | Updated: April 24, 2023 9:27 a.m.

Gift this article

## Recent State Legislation

- **TABLED** Senate Bill 83 (Wiener) - CPUC sets the timeline for interconnection by September 30, 2024. Includes $.25 carrying costs per sq ft per day.
- **Passed** Senate Bill 410 (Becker) - more comprehensive, also has a 9/20/24 CPUC deadline for determining interconnection timelines.
- **Passed** Handful of others bills, lots of focus on this issue including Assembly Bill 50 (Wood)

# Recommendations

- Create firm, predictable timelines for each part of the process, including interconnections.
- Create financial carrots and sticks to incentivize improvement.
- If necessary, outsource work to qualified third parties if delay exceeds realistic timelines.
- Establish communication channels to share information in real time

## Corey Smith, Executive Director

925.360.5090

corey@housingactioncoalition.org

HOUSING
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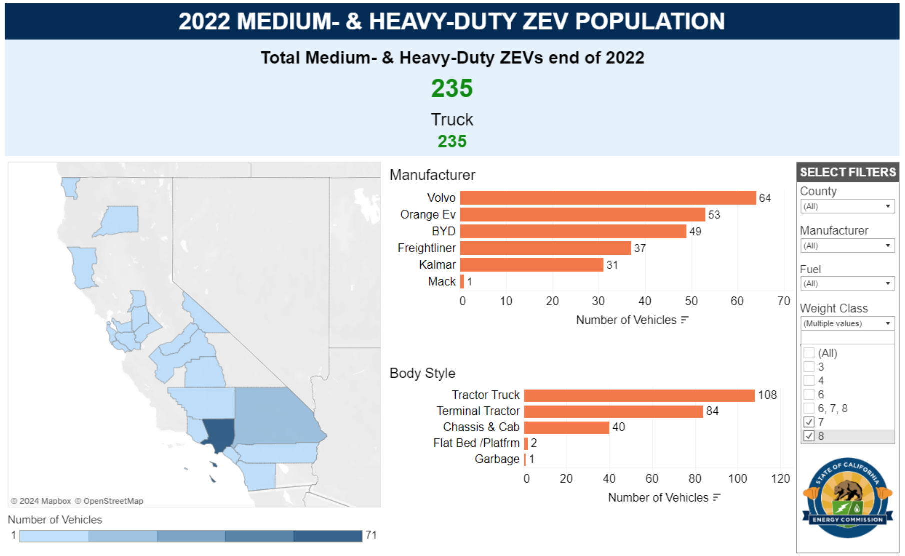
# Chris Shimoda
Senior Vice President of Government Affairs
California Trucking Association

# Infrastructure – ZE Truck Market

- ZE truck market is nascent. Estimated <0.5% market share.
- Most initial deployments in final mile delivery and yard tractors



**2022 MEDIUM- & HEAVY-DUTY ZEV POPULATION**

Total Medium- & Heavy-Duty ZEVs end of 2022

235

Truck

235

SELECT FILTERS

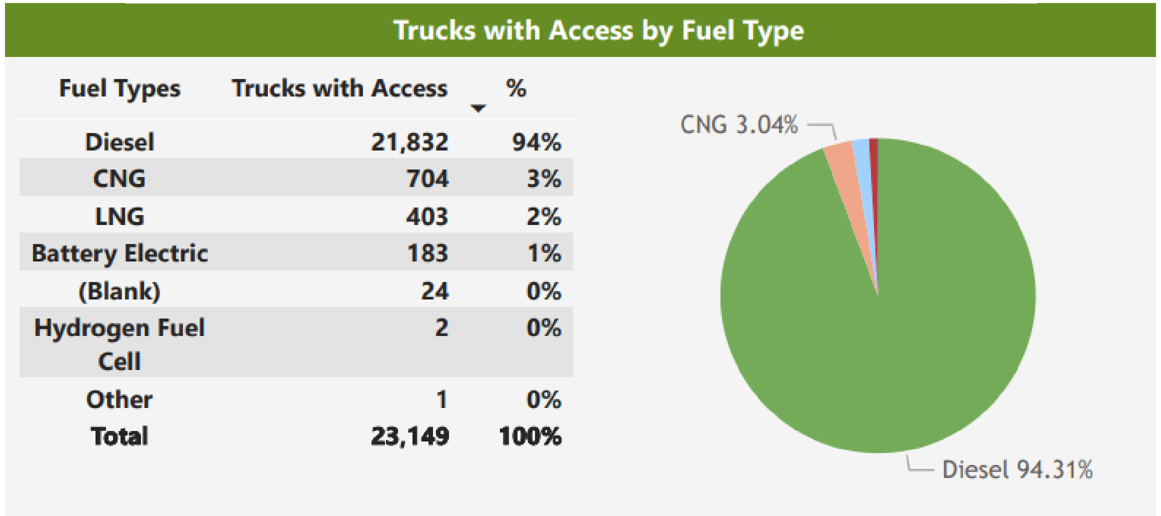
County: (All)

Manufacturer: (All)

Fuel: (All)

Weight Class: (Multiple values)

☐ (All)
☐ 3
☐ 4
☐ 6
☐ 6, 7, 8
☑ 7
☑ 8



**Trucks with Access by Fuel Type**

| Fuel Types | Trucks with Access | % |
|---|---|---|
| Diesel | 21,832 | 94% |
| CNG | 704 | 3% |
| LNG | 403 | 2% |
| Battery Electric | 183 | 1% |
| (Blank) | 24 | 0% |
| Hydrogen Fuel Cell | 2 | 0% |
| Other | 1 | 0% |
| Total | 23,149 | 100% |

Source: CEC (Top), POLA Nov 23 Gate Moves Analysis  (Bottom)

# Infrastructure – Chargers

- CARB estimated charger needs in 2022 SIP
    - Only 52% of actual ZEVs forecasted in 2035 under current regulations

- 300-600 DC fast chargers need to be installed every week to meet 2035 needs

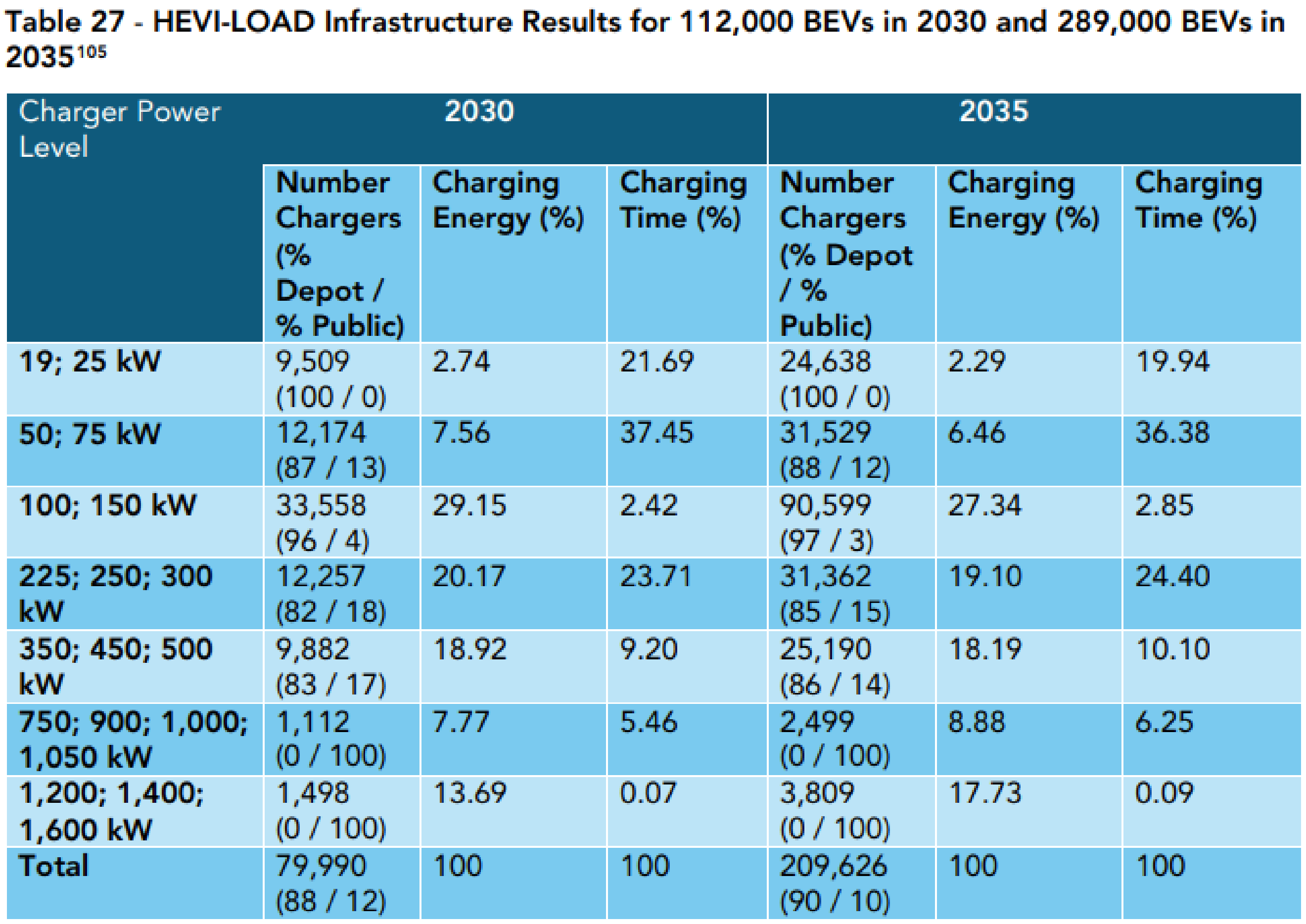


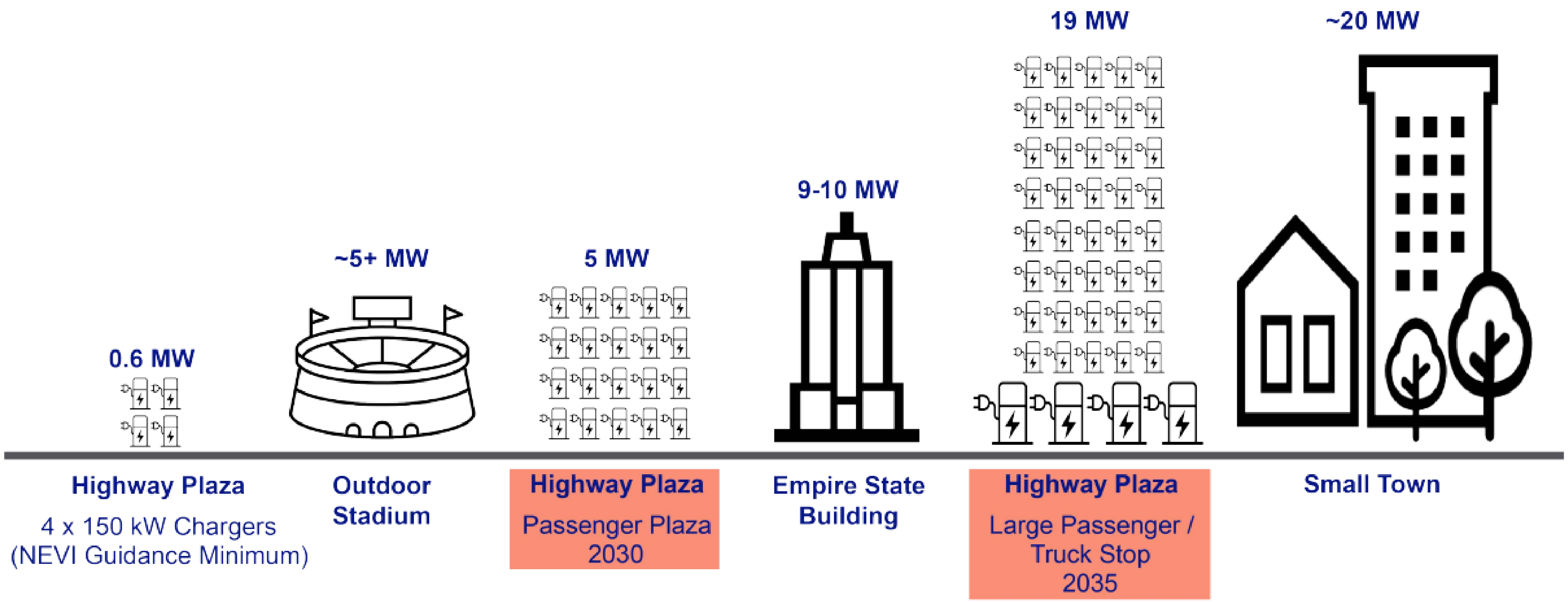
**Table 27 - HEVI-LOAD Infrastructure Results for 112,000 BEVs in 2030 and 289,000 BEVs in 2035**[105]

| Charger Power Level | 2030 | | | 2035 | | |
|---|---|---|---|---|---|---|
| | Number Chargers (% Depot / % Public) | Charging Energy (%) | Charging Time (%) | Number Chargers (% Depot / % Public) | Charging Energy (%) | Charging Time (%) |
| **19; 25 kW** | 9,509<br>(100 / 0) | 2.74 | 21.69 | 24,638<br>(100 / 0) | 2.29 | 19.94 |
| **50; 75 kW** | 12,174<br>(87 / 13) | 7.56 | 37.45 | 31,529<br>(88 / 12) | 6.46 | 36.38 |
| **100; 150 kW** | 33,558<br>(96 / 4) | 29.15 | 2.42 | 90,599<br>(97 / 3) | 27.34 | 2.85 |
| **225; 250; 300 kW** | 12,257<br>(82 / 18) | 20.17 | 23.71 | 31,362<br>(85 / 15) | 19.10 | 24.40 |
| **350; 450; 500 kW** | 9,882<br>(83 / 17) | 18.92 | 9.20 | 25,190<br>(86 / 14) | 18.19 | 10.10 |
| **750; 900; 1,000; 1,050 kW** | 1,112<br>(0 / 100) | 7.77 | 5.46 | 2,499<br>(0 / 100) | 8.88 | 6.25 |
| **1,200; 1,400; 1,600 kW** | 1,498<br>(0 / 100) | 13.69 | 0.07 | 3,809<br>(0 / 100) | 17.73 | 0.09 |
| **Total** | 79,990<br>(88 / 12) | 100 | 100 | 209,626<br>(90 / 10) | 100 | 100 |

Source: Draft 2022 SIP

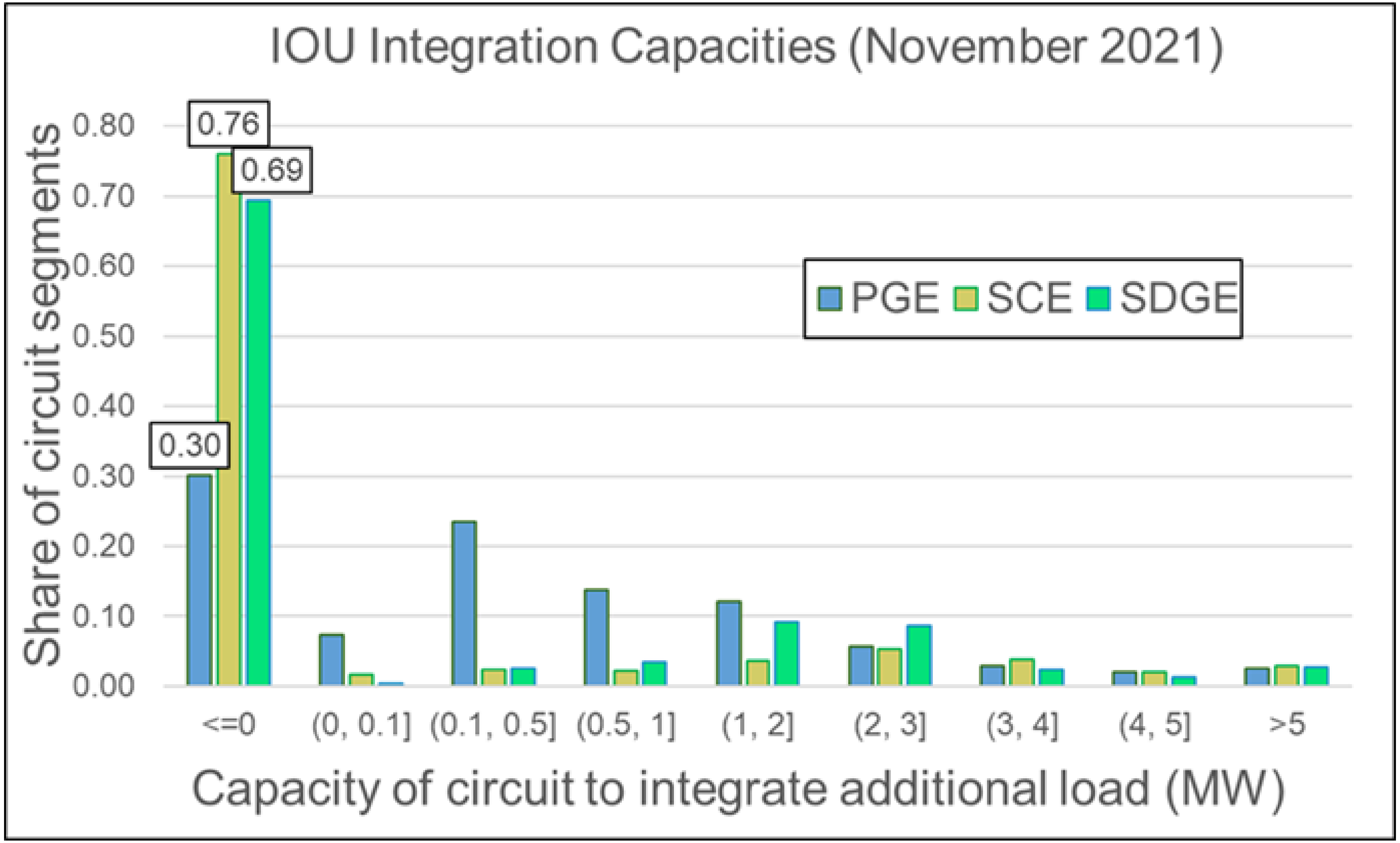
# Infrastructure – Readying for Future Deployments

Figure 21. Comparative Peak Loads for Illustrative Sites and Other Major Users[35]



Source: Electric Highways: Accelerating and Optimizing Fast-Charging Deployment for Carbon-Free Transportation (2022 – National Grid, Calstart, RMI)

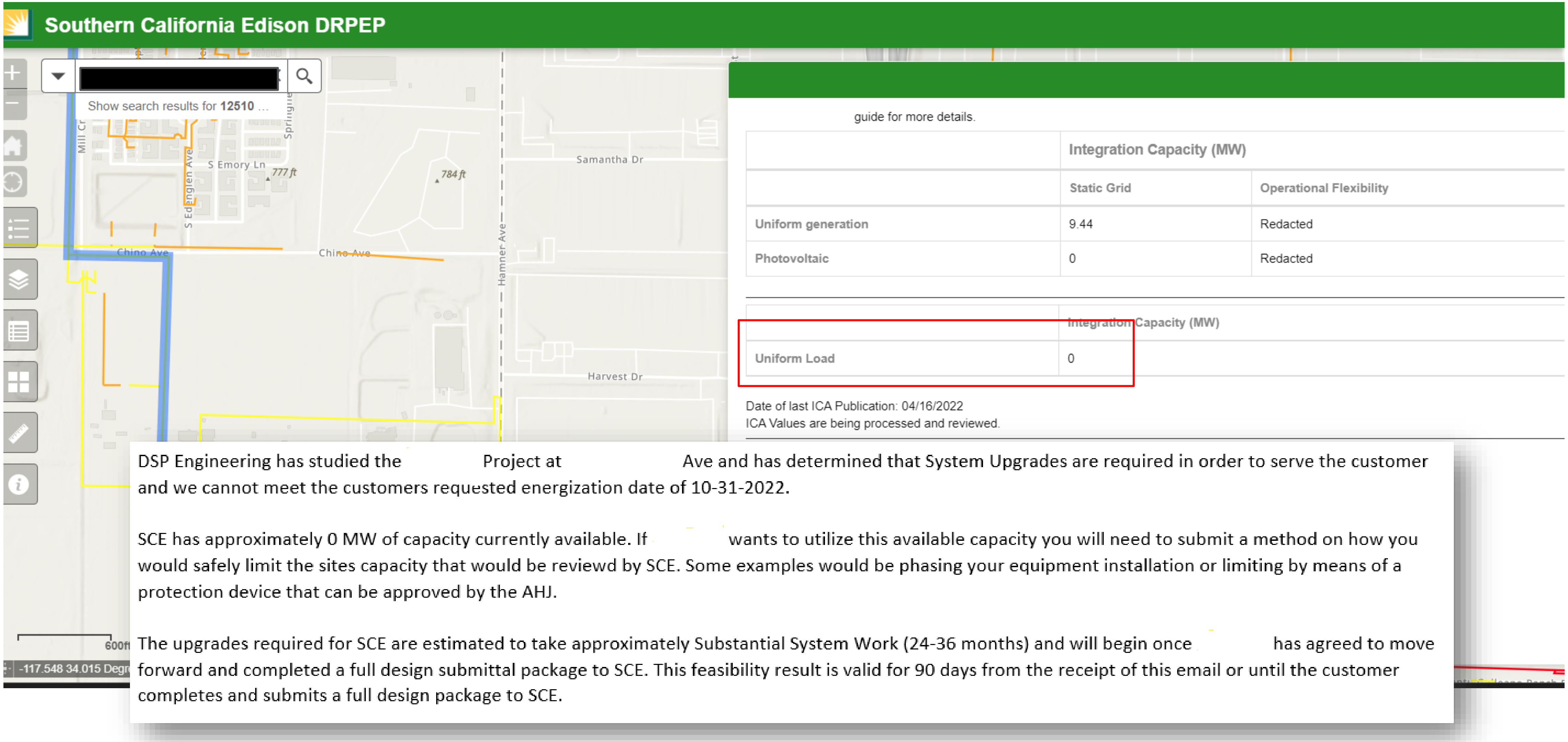
# Infrastructure – Integration Capacity



Source: CEC Presentation to ACF Workgroup

# Infrastructure – Site Specific

Source: https://drpep.sce.com/drpep/



guide for more details.

| | Integration Capacity (MW) | |
|---|---|---|
| | Static Grid | Operational Flexibility |
| Uniform generation | 9.44 | Redacted |
| Photovoltaic | 0 | Redacted |

| | Integration Capacity (MW) |
|---|---|
| Uniform Load | 0 |

Date of last ICA Publication: 04/16/2022
ICA Values are being processed and reviewed.

DSP Engineering has studied the [redacted] Project at [redacted] Ave and has determined that System Upgrades are required in order to serve the customer and we cannot meet the customers requested energization date of 10-31-2022.

SCE has approximately 0 MW of capacity currently available. If [redacted] wants to utilize this available capacity you will need to submit a method on how you would safely limit the sites capacity that would be reviewd by SCE. Some examples would be phasing your equipment installation or limiting by means of a protection device that can be approved by the AHJ.

The upgrades required for SCE are estimated to take approximately Substantial System Work (24-36 months) and will begin once [redacted] has agreed to move forward and completed a full design submittal package to SCE. This feasibility result is valid for 90 days from the receipt of this email or until the customer completes and submits a full design package to SCE.

# Infrastructure – Fleet Experience

- Two make ready project timelines provided to CTA show 4+ year timeline from contract signing for relatively straightforward small-scale projects

- Good communication from IOUs, but projects require coordination between multiple entities (e.g. landlords, AHJs, contractors, dealers, vendors)

- Complications will grow with scale and increasing loads

# Energizing Electric Truck transport

Aravind Kailas, Ph.D.

**Volvo Group**

2024-02-02

# Volvo LIGHTS provided a pathway to commercialize the Volvo’s electric truck

Many battery-electric Class 8 trucks operating in diverse, revenue-generating, customer operations today – we want this to go up!

# Charging infrastructure projects are massive construction projects

0 months

12+ months

# Problem Statement: We need power – now

Source: NRDC

- Sold electric trucks are stacking on factory and dealer lots, waiting for delivery to fleet customers because they can't get power to charging infrastructure.
- Jan. 1 this year: CARB's Advanced Clean Trucks Rule (ACT) requires MHD truck OEMs to make and sell electric trucks.
- Jan. 1 this year: CARB's Advanced Clean Fleets Rule (ACF) requires large fleets to buy electric trucks.
- The delay in energizing truck charging infrastructure poses two significant risks:
  1. Truck OEMs and fleets will struggle to meet their compliance obligation timelines.
  2. Long-term delays in compliance pose a threat to reaching state goals.

# ACT Timeline – All manufacturers are obligated

| MY | Class 2b-3 | Class 4-8 | Class 7-8 Tractors |
|---|---|---|---|
| **2024** | **5%** | **9%** | **5%** |
| **2025** | 7% | 11% | 7% |
| **2026** | 10% | 13% | 10% |
| **2027** | 15% | 20% | 15% |
| **2028** | 20% | 30% | 20% |
| **2029** | 25% | 40% | 25% |
| **2030** | **39%** | **50%** | **30%** |

In 2022, a total of 104,558 trucks in the above categories were sold in California. – Source: CARB

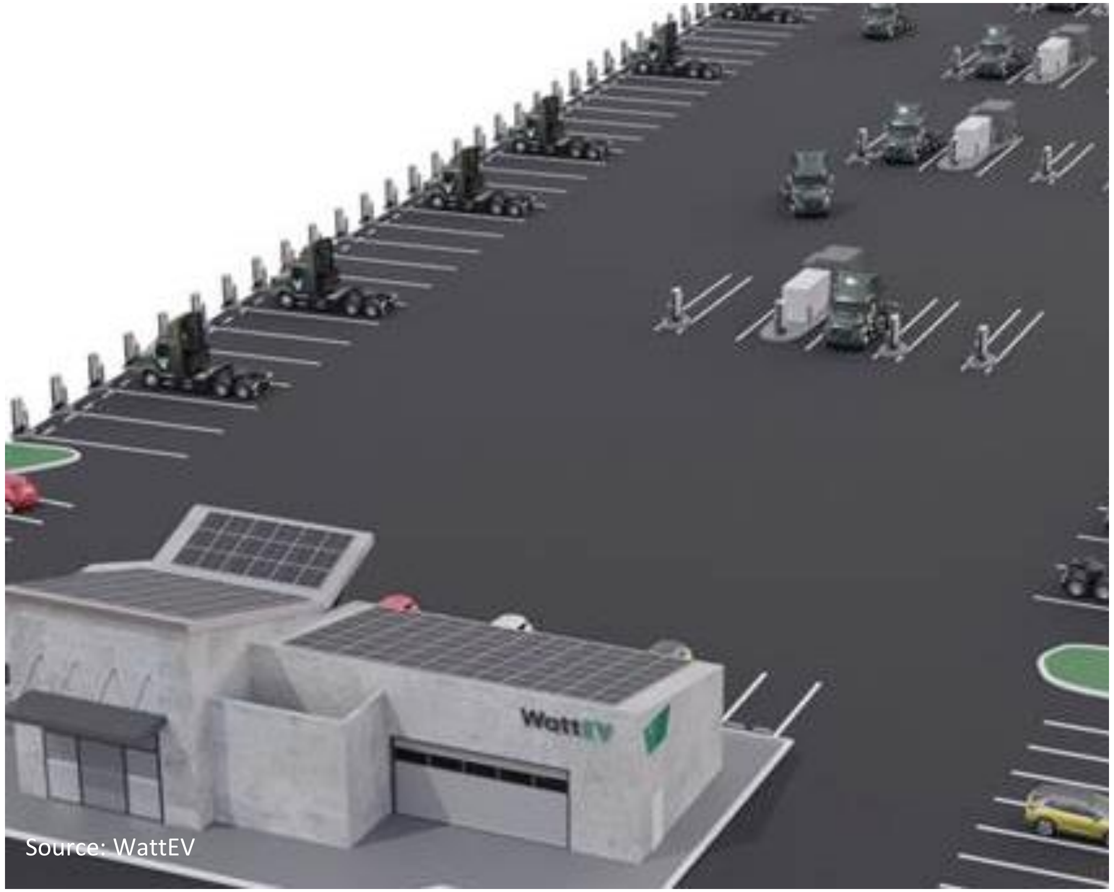
# ACF Timeline – Four fleet categories affected

1. State and local government agency fleets
2. Federal fleets
3. High priority fleets
4. Drayage fleets

| Compliance year | % of ZEVs in Group 1 | % of ZEVs in Group 2 | % of ZEVs in Group 3 |
|---|---|---|---|
| **2024** | 0 | 0 | 0 |
| **2025** | **10%** | 0 | 0 |
| **2026** | 10% | 0 | 0 |
| **2027** | 10% | 10% | 0 |
| **2028** | 25% | 10% | 0 |
| **2029** | 25% | 10% | 0 |
| **2030** | **25%** | **25%** | **10%** |

| | | |
|---|---|---|
| Box truck, van, bus w/2 axles, yard truck, light-duty package delivery vehicles | Work truck, day cab tractor, bus w/3 axles | Sleeper cab tractor, specialty vehicles |

# Every site is a snowflake



Source: WattEV

Source: Prologis

# Solutions Statement

- The CPUC must prioritize expeditious and aggressive implementation of energization timelines for California’s obligated parties under the ACT and ACF rules.
- Obligated parties need energization timelines that ensure power is available by the time the electric trucks are delivered.
- Obligated parties are prepared to collaborate with utilities to realize positive outcomes.
- Partnership is the new leadership.

# Initial takeaways from NRDC-led Coalition Survey: Barriers

1. Lack of a real-time tracker: utilities, AHJ's and developers all need same project status.
2. Lack of dedicated project manager/utility staff/resources to shepherd customer's application.
3. Lack of visibility into – and accountability for – utility's timeline for our project.
4. Equipment supply shortages.
5. Excessive upfront investment/planning required from infrastructure developer prior to any response from the IOU.
6. Lack of ability to track length of customer driven and permitting authority process / delays compared to utility processes / delays.
7. Lack of a protocol to enable applications to go back to the front of the line if there's a small change requested by the utility or permitting authority.
8. Complete results in addendum slides.

# Winning Solutions

- Require utilities to do larger bulk orders for transformers and then share the order with charging site project developers.
- Require utilities to update ICA maps or a similar tool on a quarterly or biannual basis (e.g., EPRI's eROADmap tool or the CEC's EDGE tool and Grid Needs Assessment data).
- Require utilities to allow qualified customers to acquire and install their own equipment (i.e. switchgear, transformers, etc.) so long as it meets approved, uniform technical specifications.
- Require utilities to accept "security deposits" or cash bonds from customers to reduce ratepayer financial risk in exchange for jumping to the front of the queue for service connections.
- More solutions in addendum slides.

# Goals for decision tree approach

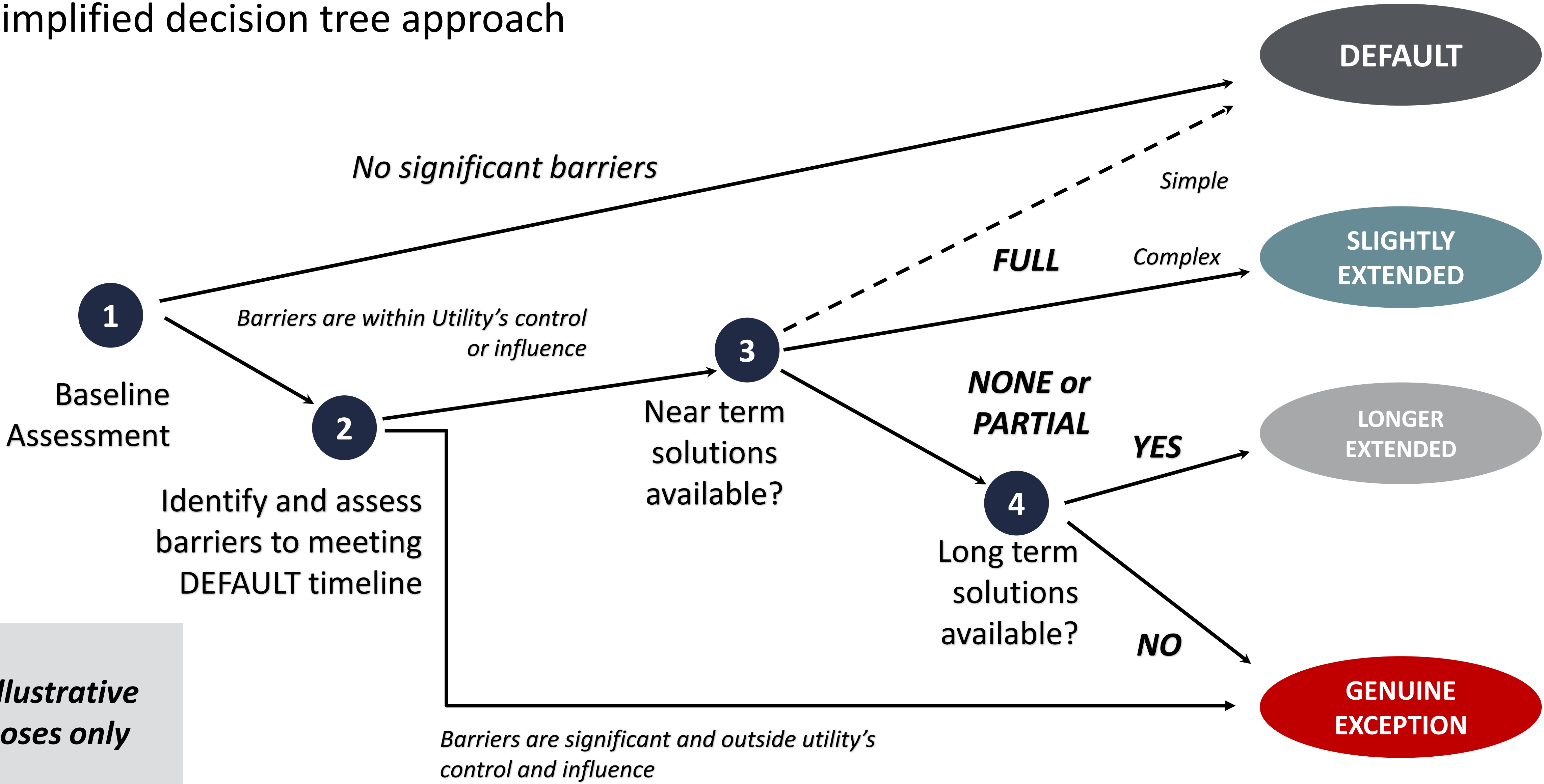
1. Establish a small set of timelines that can apply to most situations.

- Default: Utility can energize the full load requested through its standard processes, no significant barriers.
- Slightly Extended:
  - Utility and/or customer can deploy near term solutions, allowing the utility to energize the full load requested.
  - Timeline is slightly extended to permit deployment of solutions, and resolution of barrier(s) within the utility’s control and/or influence.
- Longer Extended:
  - Utility and/or customer can deploy near term solutions, allowing the utility to energize an acceptable initial level of load on *Default* or *Slightly Extended* timeline.
  - Utility develops plan to resolve significant barriers that it can control or influence.
  - Utility and customer agree on plan to serve full requested load on Longer Extended timeline.

2. Establish a set of criteria that define genuine exceptions.

# Simplified decision tree approach

TIMELINE



DEFAULT

SLIGHTLY EXTENDED

LONGER EXTENDED

GENUINE EXCEPTION

1 Baseline Assessment

*No significant barriers*

2 Identify and assess barriers to meeting DEFAULT timeline

*Barriers are within Utility's control or influence*

3 Near term solutions available?

***FULL***

*Simple*

*Complex*

***NONE or PARTIAL***

4 Long term solutions available?

***YES***

***NO***

*Barriers are significant and outside utility's control and influence*

***For Illustrative purposes only***

# Conclusions

- Thank you to CPUC staff and commissioners.
- We look forward to finding an agreeable path forward that helps all of us equitably and fairly meet the state of California's carbon-reduction and clean-air goals.
- The NRDC-led coalition is continuing to gather input from a broad cross-section of obligated entities and companies that serve them.
- We plan to share updated survey results in our Opening Comments
- We will use this feedback to flesh out the decision tree framework
- We welcome your comments on our proposed approach

# Q&A

# Panel 4 – Customer Experience Requesting New and Upgraded Service from the Utility – Part 2

- Priscilla Rodriguez, Assistant Vice President of California Cotton Ginners & Growers Association and Western Agricultural Processors Association

# Michelle Bushnell

- $2^{nd}$ District Supervisor, County of Humbolt

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# Energization Challenges for Agricultural Operations

**Priscilla Rodriguez**
**Assistant Vice President**

# Challenges

- Severe lack of infrastructure
  - Inability to connect
    - Almond cold storage in Madera
    - Citrus Packing House in Sanger

# Challenges

- Severe lack of infrastructure
  - Significant time delays
    - Pistachio huller in Kern County
    - Almond processor in Stanislaus County
    - Farm shop in Fresno County
  - Numerous examples of lack of capacity today.

# Impacts

- Increased cost of temporary solutions
- Loss of sales/jobs
- Climate and Air Quality Goals Compromised

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# Current Situation

- Coming regulatory mandates
  - CARB Advanced Clean Fleets Rule
    - Electric trucks
  - CARB LSI Regulation
    - Electric forklifts

# Infrastructure Challenges

- Already maxed out in many areas
- DC fast truck chargers are up to 1 MW each

# Affordability

- How is all of this infrastructure going to be paid for?
- PG&E ag rates increased over 27% year over year
- NEM Aggregation eliminated
  - No more solar for Ag

# In Search of a Solution

- Several meetings between various high level representatives
  - EO, Board Member & Staff of CARB
  - Regional Utility Directors for PG&E, SoCal Edison
  - CPUC/CEC Staff
  - SJVAPCD APCO
- Survey energy needs

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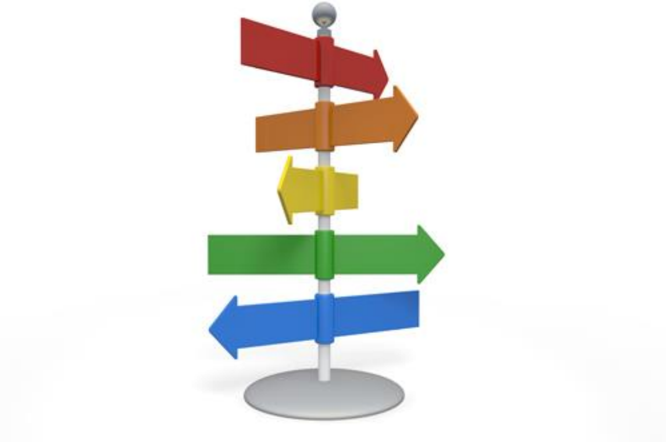
# Where do we go from here?

- Need to understand infrastructure needs
  - How much?
  - Where?
  - When?
- Need to build Infrastructure
    - Plan
    - Capital
- If the state's deadline can't be met, then the state needs to change the deadlines



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# Meredith Alexander

- Consultant to Microsoft

# Q&A

# 10-Minute Break

# General Discussion on Developing Energization Timing Targets and Reporting Processes

- How should the Commission develop energization timing targets?
  - What timeframe do customers consider to be “timely” and “untimely” for energization?
  - How should the Commission determine whether an energization timeline is reasonable?
  - What data should the Commission use to determine reasonable average and maximum timing targets? What, if any, additional data collection efforts should the Commission direct to further inform energization timing targets?
  - Should the Commission adopt state-wide energization timelines, or should the timelines be utility-specific? Why or why not?
  - Should the Commission develop different energization timing targets that are specific to customer or project types? If yes, what customer or projects types should have separate timelines? If not, why?
  - What measures should be considered to ensure the energization timing targets do not result in certain energization requests being prioritized more than others?
  - What, if any, are the differences in the energization processes for customers requesting new service compared to upgraded service? How should these differences be reflected in the energization timing targets?

# General Discussion on Developing Energization Timing Targets and Reporting Processes

- What are the key milestones and metrics for the customer and utility to complete for each step in the Rule 15 and 16 energization process? How do these milestones align with the customer's energization timing expectations?
  - What are the key barriers the impact a utility's ability to meet a customer's requested energization completion date? How should the energization timing targets recognize the realities of the timing needed to complete each step in the energization process, while also reflecting efforts to accelerate the energization process?
  - How should the energization timing targets recognize the options for Electric Rule 15 and 16 that allow the customer to choose if the utility or applicant will complete certain tasks?
  - How should local ordinances that may cause certain projects to be delayed (i.e., undergrounding requirements, limits to the time-of-day construction can be performed, etc.) be factored into the energization timing targets?

# General Discussion on Developing Energization Timing Targets and Reporting Processes

- What innovations or process improvements are being considered or implemented by the utility and/or applicant to streamline the energization processes?
  - What are the specific steps in the energization process that these innovations or process improvements seek to improve? How can these efforts be scaled across the utilities?
  - What regulatory barriers are preventing the utility and/or customer from streamlining the energization process?
- How should delays that are the responsibility of the applicant or another stakeholder be factored into the energization timing targets?
  - What efforts are the utilities currently taking to minimize delays that are not in their direct control?
  - Should the Commission direct the utilities to pursue efforts to minimize delays that are not in their direct control? If yes, what efforts should the Commission consider? If not, what ways, if any, can the utilities support overcoming the delay(s)?
  - How should the utility demonstrate to the Commission and public that they made these efforts early in the energization process?
  - How should the Commission factor issues that are not within the utilities' direct control (e.g., authorized funding, staffing, supply chains, etc.) in the energization timelines?
- What venues do customers currently pursue to seek resolution to ongoing energization delays?
  - How are the utilities tracking the causes and efforts to resolve the delay(s)? Is this information made public by customers or the utilities? If so, where can this information be viewed?
  - Do the utilities and/or Commission have an existing venue that can allow customers to report energization delays? If yes, identify the venue. If no, what type of venue is most conducive to ensure energization delays are reported and followed up on?

# Next Steps

| | |
|---|---|
| Opening Comments on OIR | February 20, 2024 |
| Reply Comments on OIR | March 1, 2024 |
| Scoping Memo Issued | March 2024 |
| Party Comments on Scoping Memo | April/May 2024 |

# Thank You