Prepared for the California Public Utilities Commission

Aliso Canyon OII Phase 3 Research

Workshop #3: Portfolio 1–4 Modeling Approach, Inputs, and Results and Portfolio 5 Considerations

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November 3, 2021

Agenda

Schedule	Topic	Session Lead(s)
9:30 – 9:35	Welcome, Summary of Phase 3 Schedule, Introduction and Ground Rules	ALJ Zhen Zhang, CPUC
9:35 – 9:40	Introductory Remarks	Commissioner Martha Guzman-Aceves, CPUC
9:40 – 10:00	Recap of FTI/GSC Modeling Approach	Ken Ditzel, FTI
10:00 – 10:15	Base Case Updates	Mitch DeRubis, FTI Tim Sexton, GSC
10:15 – 10:35	Results Summary	Ken Ditzel, FTI
10:35-10:40	**Break**	
10:40-11:15	Portfolio 1: Gas Transmission Expansion	Tim Sexton, GSC Ken Ditzel, FTI
11:15 – 11:50	Portfolio 2: Gas Demand Reduction	Venki Venkateshwara, FTI Ken Ditzel, FTI
11:50-12:50	**Lunch Break**	
12:50 – 1:25	Portfolio 3: Electric Generation Additions	Mitch DeRubis, FTI Ken Ditzel, FTI
1:25 – 2:00	Portfolio 4: Electricity Transmission	Venki Venkateshwara, FTI Ken Ditzel, FTI
2:00 – 2:15	Proposal for Portfolio 5: Staged Industrial Demand Response and Building Electrification	Ken Ditzel, FTI Mitch DeRubis, FTI
2:15 – 2:25	**Break**	
2:25 – 3:25	Q&A on FTI Research	FTI, GSC
3:25 – 3:30	Research Report Next Steps	Ken Ditzel, FTI
3:30 – 4:00	Party Implementation Discussion	Commissioner Guzman-Aceves’ Office
4:00 – 4:25	Public Comment	
4:25 – 4:30	Closing and Next Steps in the Proceeding	ALJ Zhang, CPUC

Recap of FTI/GSC Modeling Approach

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Recap of FTI/GSC Modeling Approach

Gas Shortfall Recap

Updated analysis shows a peak day shortfall of 395 MMcf/d in 2027 and 323 MMcf/d in 2035

Units in MMcf/d

	August 2021 Results	
	54% Inventory	*82% Inventory*
Demand Category	2027	2035
Core	3,101	2,987
Non-Elec Gen Non-Core	670	653
Elec Gen	745	803
Total	**4,516**	**4,443**
Electric Generation (EG) Demand Breakout		
FTI-PLEXOS	621	682
Enhanced Oil Recovery (EOR) Electric	52	50
Refinery Electric	72	71
Total	**745**	**803**
EG Demand Reduction to Balance Model		
Base Requirements (above)	4,516	4,443
Demand Reduction (EG)	(395)	(323)
Total Served in Hydraulic Model	**4,121**	**4,121**

Notes

- EG demand reductions undertaken at least efficient (highest heat rate) generation facilities first.
- Updated Natural Gas Delivery Reductions equate to approximately 59,000 MWh and 38,000 MWh of reduced winter peak day gas generation in 2027 and 2035, respectively.

Recap of FTI/GSC Modeling Approach
Investment Portfolios

Gas Transmission	Demand Reduction	Integrated Resource Plan (IRP) Mix	Electric Transmission	Hybrid
<u>Northern Zone</u>: Expansion facilities to access natural gas at the SoCal border. <u>Wheeler Ridge Zone</u>: Expansion facilities to access off-system storage via PGE. Costs based on utility filings to CPUC and other public datasets.	Expansion of gas-side activities plus new investments assumes significant regulatory support from CPUC, mandates from AB3232, and others. Gas-only, based on analysis of current programs plus public planning studies.	Incremental demand response, storage, and renewables added in the same ratio as shown in the current IRP, excluding solar New builds are scaled *pro rata* in order to close the MW gap. No new thermal generation is included.	Use Base Case modeling to determine where and by how much current transmission limits must be relaxed to allow increased transmission from outside California to meet the shortfall. Estimate cost of the necessary transmission changes, using generic estimates. .	<u>To be Discussed Today</u> Construct a hybrid portfolio made up of components of the four portfolios analyzed to date, considering ability to meet shortfall, cost, benefits, and timing

Recap of FTI/GSC Modeling Approach

Analytical Overview

Operational Analysis

Simulate the operation of the electric and gas systems on an hourly basis under peak day conditions to determine how reliant they are on Aliso Canyon. Based on those results, specify multiple packages of investments that would allow for the facility to retire without impacting reliability.

Benefits Analysis

Conduct long-run economic analysis to determine which of the investment options is most beneficial and/or least expensive from the ratepayers' perspective.

Production Cost Modeling → **Hydraulic Modeling** → **Identify Investments** → **Economic Modeling** → **Financial Modeling**

WORKSTREAM 1 | **WORKSTREAM 2**

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Recap of FTI/GSC Modeling Approach

Workstream 2 Overview

Investment portfolios scaled to close the shortfall

1 Simulation of a gas hydraulic model along with power and gas market models to estimate impacts

2 Research and analysis of financial costs to build new infrastructure and financial modeling to calculate the cost-benefit of each option

3 Comparison (ranking) of portfolio costs and benefits

Recap of FTI/GSC Modeling Approach

Power and Gas Market Models

PLEXOS and GPCM are industry-accepted modeling tools for power and gas markets, often used by utilities, investors, regulators, system operators, and researchers.

FTI/GSC populated them using public and proprietary databases compiled by the Project Team and calibrated to observed markets.

	PLEXOS *(Power)*	**GPCM** *(Gas)*
Solver	MIP with co-optimization of reserves	RBAC Network Optimizer (custom LP algorithm)
Key Model Inputs	Existing generators (EIA); Planned generators (TPP and CPUC order); Load (CEC); and Transmission (SERVM)	Existing and planned pipelines, storage, and LNG facilities
Stochastic	Yes, forced outages	No
Time-step	Hourly	Monthly
Forecast Periods	2027 and 2035	2027 and 2035
Website	https://energyexemplar.com/solutions/plexos/	https://rbac.com/gpcm-natural-gas-market-model-description/

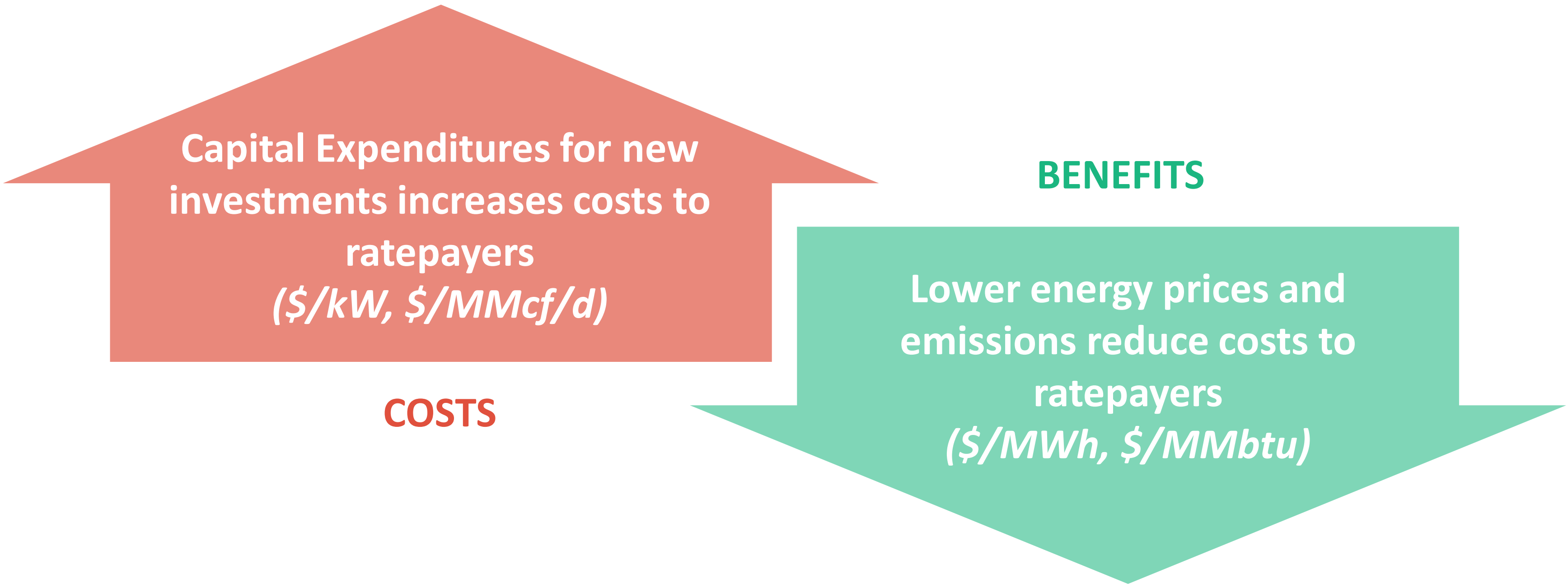
Recap of FTI/GSC Modeling Approach

Hydraulic Model

1	Gregg Engineering NextGen Hydraulic Modeling Software
2	Supports Steady State and Transient Simulations
3	Input Facility Data Based Upon CPUC Phase 2 Model
4	Used by Natural Gas and Liquids pipelines worldwide, including majority of US Interstate Pipelines
5	Website: https://www.greggeng.com/software-solutions/nextgen-simulation-suite/

Recap of FTI/GSC Modeling Approach

Cost-Benefit Analysis



Cost-Benefit Analysis Process

- Simulate gas and electric markets using PLEXOS and GPCM to estimate the benefits from reduced energy prices, if applicable, and emission reductions from new infrastructure.
- Benefits will be compared to levelized capital costs, annual operating costs, and emissions increases, if applicable.

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Recap of FTI/GSC Modeling Approach

Presentation Framework for each Portfolio

Portfolio Description	Technical Solution	Modeling Inputs	Modeling Results	Cost-Benefit Analysis
Description of the intent of the portfolio, its context, general background assumptions	Description of the technical solution for the portfolio and how it would address the projected shortfall without Aliso Canyon	Description of the technical and cost-benefit modeling inputs required to assess the portfolio's impact on addressing the shortfall, CO2 increases/reductions, and other key inputs	Description of the technical and economic results from the modeling	Description of the cost benefit analysis results for the portfolio

Base Case Update

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Base Case Update

Changes to Base Case Generation Fleet

Previous Base Case

Existing and Planned Generators

+

2019 IRP Dataset

Updated Base Case

Existing and Planned Generators

Transmission Planning Portfolio (TPP) Dataset

+

11.5 GW Procurement Order

Approach to Implement 11.5 GW Procurement Order

1 Review procurement order focused on total Net Qualifying Capacity (NQC) by technology and Load Serving Entity (LSE) obligations for the three Investor-Owned Utilities (IOUs)

2 Analyze TPP RESOLVE-selected technology additions by technology and NQC

3 Supplement TPP portfolio to comport with procurement order NQC and LSE obligations

4 Revised Portfolio

Base Case Update

Procurement Order Requirements

Net Qualifying Capacity, MW

Procurement Category	2023	2024	2025	2026	Total
Zero-emissions generation, generation paired with storage, or demand response resources, required *by* 2025, not necessarily in 2025			2,500		**2,500**
Firm zero-emitting resources					**1,000**
Long-duration storage resources					**1,000**
Total annual capacity requirements	**2,000**	**6,000**	**1,500**	**2,000**	**11,500**

Base Case Update

TPP Includes 7,438 MW NQC from RESOLVE-selected Resources

Methodology

1. Group “Solar + 4h Storage” and “Wind + 4h Storage” by zone to apply proper Effective Load Carrying Capability (ELCC) for hybrid resources – unpaired solar, wind, and batteries receive standalone ELCCs
2. Apply ELCCs from CPUC’s Energy Division to nameplate TPP capacities
3. Apply TPP NQC builds against the various 11.5 GW procurement order requirements

TPP RESOLVE-selected resources

Resource	MW NQC
Hybrid (Solar + 4h Storage)	3,056
Hybrid (Wind + 4h Storage	1,740
Geothermal	-
8h Storage	747
Gas	-
4h Storage	1,563
Solar	75
Wind	257
Total	**7,438**

Additions to TPP Portfolio to Meet 11.5 GW NQC Requirement

Methodology

1. The TPP falls short of each requirement
2. Supplemented the TPP capacity with
   a. Solar + 4h Storage
   b. Wind + 4h Storage
   c. Standalone 4h Storage

   in proportions provided by the CPUC Energy Division
3. Added 1,000 MW NQC of Geothermal
4. Added 253 MW NQC of 8h Storage
5. Requirements for total capacity, LLT, and zero-emissions are met

Net Qualifying Capacity, MW

Resource	TPP	Additional	Total
Hybrid (Solar + 4h Storage)	3,056	1,700	**4,756**
Hybrid (Wind + 4h Storage	1,740	74	**1,814**
Geothermal	-	1,000	**1,000**
8h Storage	747	253	**1,000**
Gas	-	-	**-**
4h Storage	1,563	1,035	**2,598**
Solar	75	-	**75**
Wind	257	-	**257**
Total	**7,438**	**4,062**	**11,500**

Base Case Update

Effect on Peak Day Electric Generation Gas Demand

Discussion

1. Increasing the renewable and storage build reduces the gas burn by electric generation during the peak day considerably, particularly in 2027.
2. The EG burn is now expected to *increase* from 2027 to 2035 due to rising electric demand and limitations on how much gas-fired generation can be displaced.
3. The increase is more than offset by the expected decline in core demand over the same period.
4. Totals exclude gas demand for cogeneration by refineries and EOR.

Peak Day Gas Demand for Electric Generation, MMcf

	2027	2035
Previous (as of May 2021)	840	839
Current	621	682
Change	-219 (-26%)	-157 (-19%)

Assumptions Review

Key Assumptions Underlying Analysis of Capacity Shortfall

Assumptions Updated versus Workshop #2

1	Storage Available at 54% (2027) and 82% (2035) of Inventory (Adopted Based Upon Workshop #2 Feedback)
2	Gas Use for Available Generation based upon TPP Dataset and Procurement Order (Workshop #2 based upon 2019 IRP Dataset)

Assumptions Unchanged from Workshop #2 Shortfall Analysis

3	85% Pipeline Utilization in Northern and Southern Zones and 100% in Wheeler Ridge Zone (Current System Capacity) – Consistent with Phase 2 Assumptions
4	Generation Demand reduced to reflect Unserved Load due to Capacity Restrictions
5	Honor Rancho Used to support in-day demand fluctuations / Aliso Canyon Removed from Service (i.e., no withdrawals from Aliso Canyon)
6	Core / Non-Core Gas Demand Source – California Gas Report

A key finding is that the removal of Aliso creates a gas deliverability shortfall that translates to unserved electric energy.

Assumptions Review

Hourly Demand Profiles Utilized (Unchanged from Nov 2020)

- As part of its Phase 2 analysis, CPUC undertook a detailed review of SoCalGas hourly profiles for core and non-core customer classes
- Based on this review, CPUC concluded that aggregation of demand profiles across zip codes on the system validates SoCalGas core hourly profile assumption and CPUC utilized SoCalGas hourly demand profiles in its analyses
- GSC/FTI adopted CPUC approach and utilized SoCalGas hourly profiles in its Phase 3 models of SoCalGas system
- EG Profiles developed by FTI using PLEXOS model for years 2027 and 2035

Updated Shortfall Analysis Results

Hydraulic Model Results: Calculated Natural Gas Deliverability Shortfall

Phase 3 Model Results (MMcf/d)

	Nov 2020 (Workshop #2) Results		Updated Results	
	(90% Storage Inventory)		54% Inventory	82% Inventory
Demand Category	**2027**	**2035**	**2027**	**2035**
Core	3,101	2,987	3,101	2,987
Non-Elec Gen Non-Core	670	653	670	653
Elec Gen	964	960	745	803
Total	4,735	4,600	4,516	4,443
EG Demand Breakout				
FTI-PLEXOS	840	839	621	682
EOR Electric	52	50	52	50
Refinery Electric	72	71	72	71
Total	964	960	745	803
EG Demand Reduction to Balance Model				
Base Requirements (above)	4,735	4,600	4,516	4,443
(Demand Reduction (EG)) / Shortfall	(434)	(318)	(395)	(323)
Total Served in Hydraulic Model	4,301	4,284	4,121	4,121

Notes

- Iterations of Hydraulic Models were developed wherein EG demand reductions were implemented at various levels to determine if system (absent Aliso Canyon withdrawals) could support deliveries while maintaining minimum operating pressures and recovering line pack daily. The shortfall quantity depicted in the table reflects the quantity of EG demand reduction (in MMcf/d) that was required to enable system deliverability to meet demand requirements. Reductions of demand below this level result in an inability to always maintain minimum operating pressures and/or an inability to fully recover line pack on a day.
- EG demand reductions undertaken at least efficient (highest heat rate) generation facilities first.
- Updated Natural Gas Delivery Reductions equate to approximately 59,000 MWh and 38,000 MWh of reduced winter peak day gas generation in 2027 and 2035, respectively.

Updated Shortfall Analysis Results

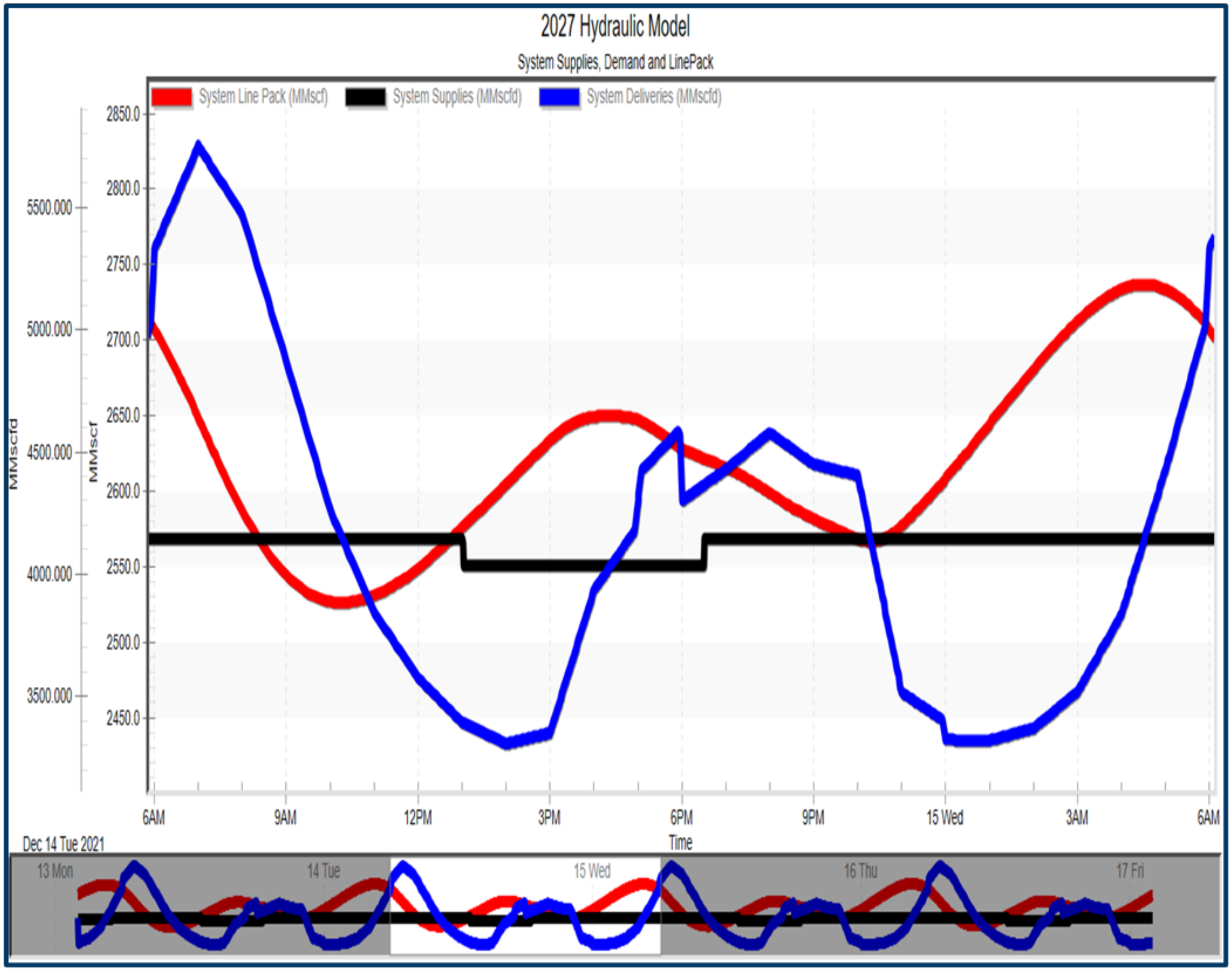
Hydraulic Model (2027): Hourly Supply/ Demand/ Line Pack

Discussion

1. Line Pack fully recovers from 2,575 MMcf at 6AM start to 2,576 MMcf at 6AM twenty-four hours later.

2. Hourly Delivery Swings range from low of 3,307 MMcf/d at 2:00 PM to high of 5,752 MMcf/d at 7:00 AM.

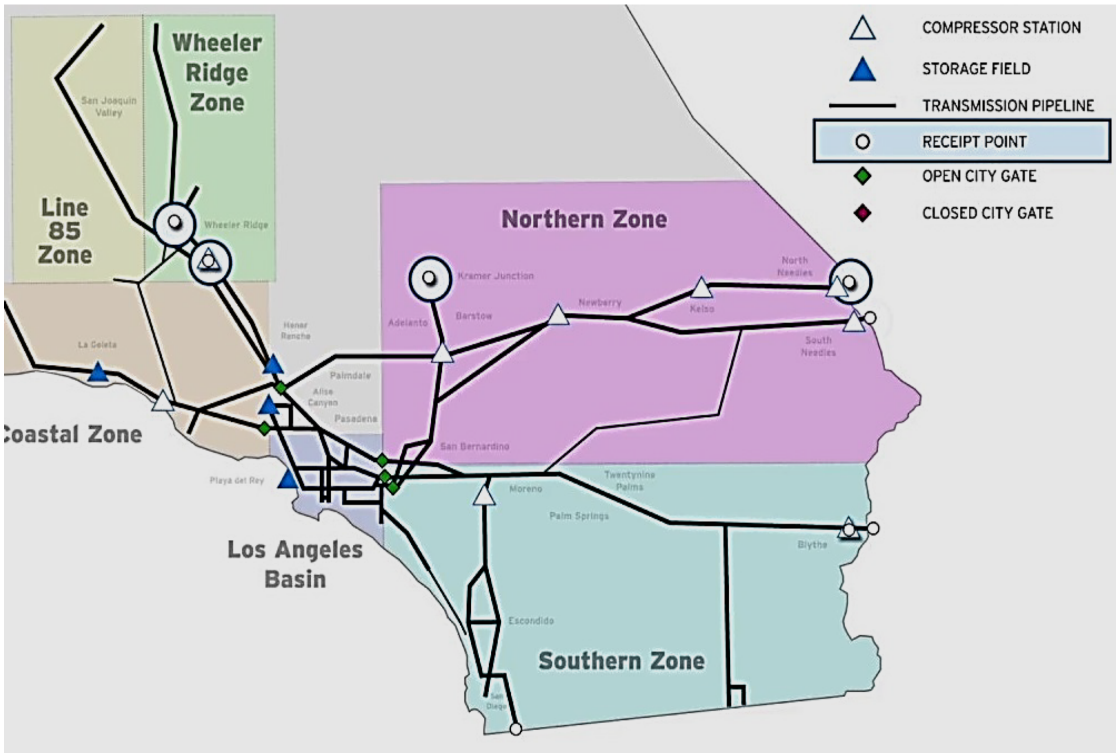
3. Supply Changes supported by line pack and withdrawal quantity adjustments made during the day at Honor Rancho.



Updated Shortfall Analysis Results

Subsystem Line Pack: Hydraulic Model (2027)

Line Pack recovers for ALL Zones in 2027 1-in-10 Demand Day Model with Adjusted Demand



Zone	Day 1 – Midnight LinePack (MMscf)	Day 2 – Midnight LinePack (MMscf)
Coastal Zone	268.5	268.7
San Diego Zone	51.3	51.3
LA Basin Zone	361.8	362.1
Valley Zone	183.1	183.1
Northern Zone	749.8	750.3
Southern Zone	990.0	990.1

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Updated Shortfall Analysis Results

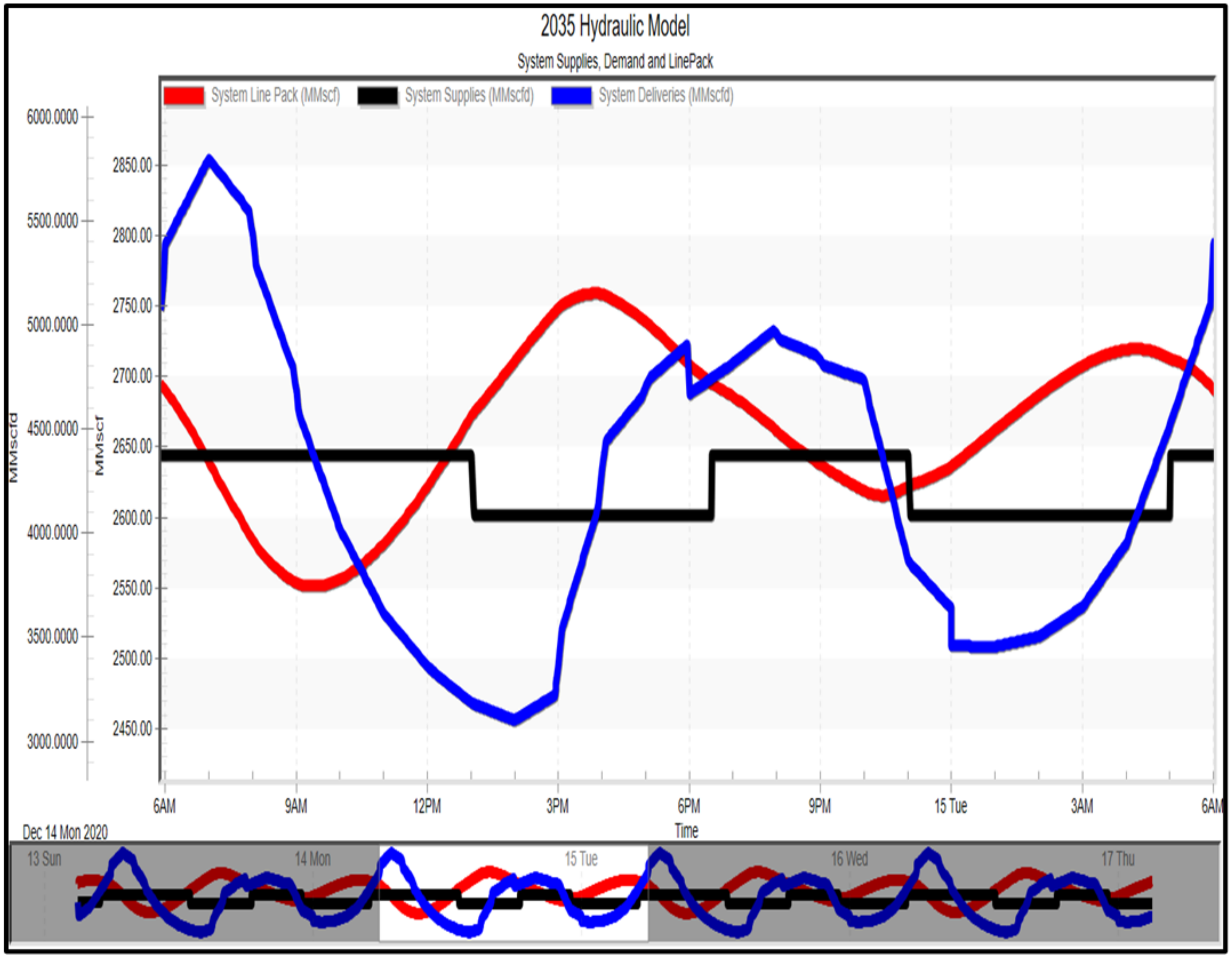
Hydraulic Model (2035): Hourly Supply / Demand / Line Pack

Discussion

1. Line Pack fully recovers from 2,691 MMcf at 6AM start to 2,691 MMcf at 6AM twenty-four hours later.

2. Hourly Delivery Swings range from low of 3,102 MMcf/d at 2:00 PM to high of 5,797 MMcf/d at 7:00 AM.

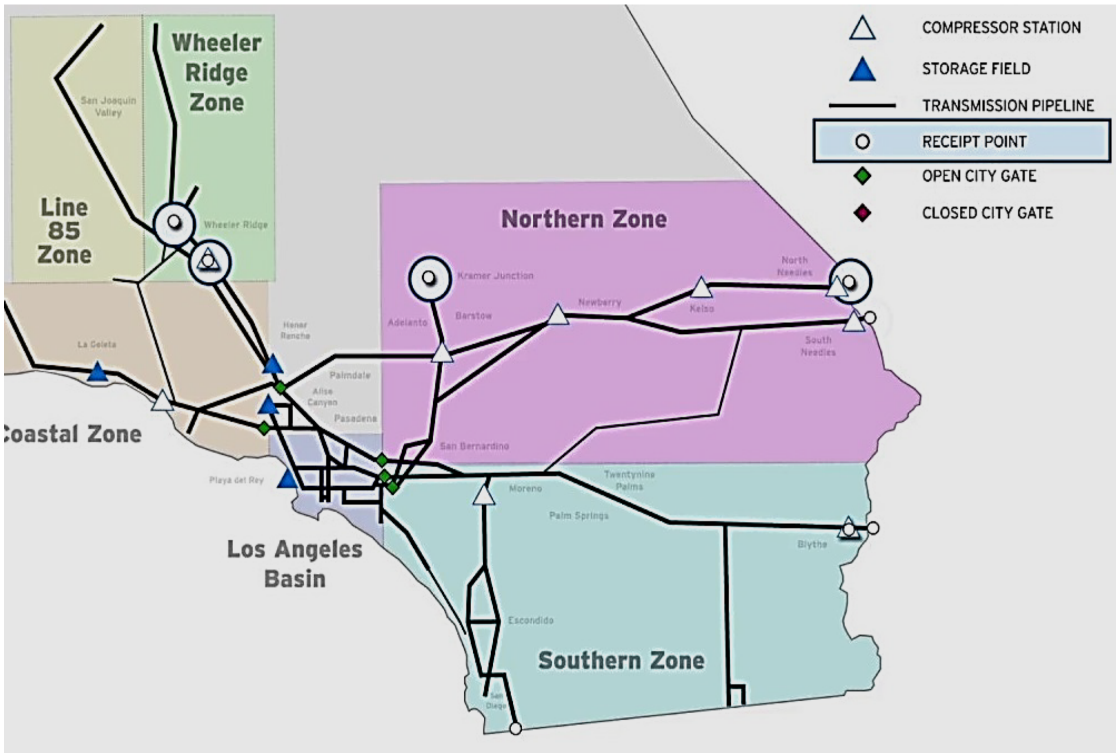
3. Supply Changes supported by line pack and withdrawal quantity adjustments made during the day at Honor Rancho.



Updated Shortfall Analysis Results

Subsystem Line Pack: Hydraulic Model (2035)

Line Pack recovers for ALL Zones in 2035 1-in-10 Demand Day Model with Adjusted Demand



Zone	Day 1 – Midnight LinePack (MMscf)	Day 2 – Midnight LinePack (MMscf)
Coastal Zone	278.7	278.8
San Diego Zone	48.7	48.7
LA Basin Zone	374.8	374.8
Valley Zone	183.5	183.8
Northern Zone	792.1	792.3
Southern Zone	958.5	957.8

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Updated Shortfall Analysis Results

Hydraulic Model Results Summary

Delivery Quantities

1. All Core and Non-Core (non EG) deliveries maintained
2. EG deliveries reduced by 395 MMcf/d and 323 MMcf/d in 2027 and 2035 models to accommodate potential impact of removing Aliso Canyon from service

Pressures

1. System Pressures maintained below MAOP
2. Delivery Pressures maintained above minimum allowable operating pressures with a few isolated variances in San Joaquin Valley
3. Isolated San Joaquin Valley pressures fell below minimum allowable operating pressure by approximately 50 psig or less

Line Pack

1. Line Pack recovers over twenty-four-hour period

Supplies

1. Honor Rancho Storage and Line Pack Successfully utilized to Balance Demand Variations during the day.
2. All Other Pipeline and storage receipt points held constant at planned levels

Cost-Benefit Summary

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Cost-Benefit Summary

Cost and Benefit-Cost Ratio Results

2027 Portfolios (Millions of 2019$ in 2027)

Portfolio	Costs	Benefits	Benefit-Cost Ratio	Net Benefits
1a. Northern Zone Expansion	$47.7	$0	N/A	($47.7)
1b. Wheeler Ridge Expansion	$150.3	$0	N/A	($150.3)
2. Gas Demand Reduction	$252.7	$116.3	0.46	($136.4)
3. Generator Additions	$636.8	$609.5	0.96	($27.3)

2035 Portfolios (Millions of 2019$ in 2027)

Portfolio	Costs	Benefits	Benefit-Cost Ratio	Net Benefits
1a. Northern Zone Expansion	$20.9	$0	N/A	($20.9)
1b. Wheeler Ridge Expansion	$105.9	$0	N/A	($105.9)
2. Gas Demand Reduction	$212.1	$145.8	0.69	($66.3)
3. Generator Additions	$567.8	$681.6	1.20	$113.7
4a. Transmission Expansion	$111.2	$168.1	1.51	$56.9
4b. Transmission Expansion	$79.6	$147.5	1.85	$67.9

Annual Cost Discussion

- The lowest cost solution is the Northern Zone expansion
- Generator Additions are the highest cost portfolio, but provide 8760 wholesale price and GHG reduction benefits
- The transmission portfolio solutions generally are within the same cost range as the gas infrastructure portfolio solutions

Benefit-Cost Ratio Discussion

- The transmission portfolio solutions have the highest benefit-cost ratio
- Generator Additions have a benefit-cost ratio approximately >= 1.0
- Gas infrastructure portfolio solutions only provide peak day replacement of Aliso and thus have no benefit-cost ratios
- The Gas Demand Reduction portfolio's benefit-cost ratio would improve with the removal of electrification

Portfolio 1:
Gas Transmission System Expansion

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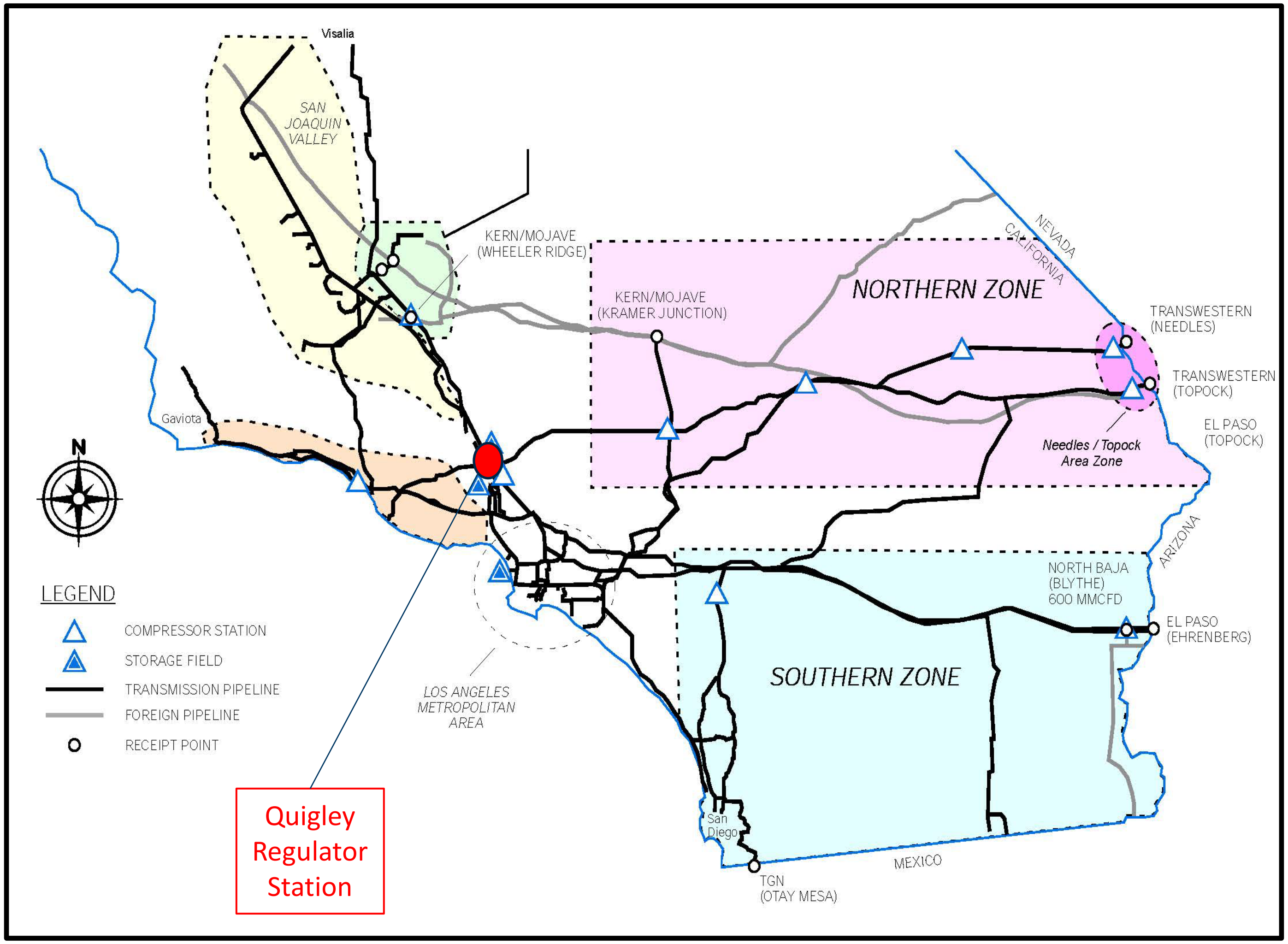
Portfolio 1: Gas Transmission System Expansion

Overview of Portfolios

Two gas transmission portfolio solutions were identified: 1. Northern Zone Expansion and 2. Wheeler Ridge Zone Expansion to access third party storage via California Gas Transmission (CGT)

Portfolio 1a
Northern Zone Supply Expansion

Portfolio 1b
Wheeler Ridge Expansion to Access Third Party Storage



Notes

- Regulator Stations generally consist of valves, pressure reducing equipment and yard piping and are used to regulate natural gas pressures and flows to ensure that pressures are reduced prior to gas flowing from a higher pressure operating area to a lower pressure operating area.

Portfolio 1: Gas Transmission System Expansion

Detailed Assumptions: RPU/Outage and Storage

- **RPU / Outage Assumption**
  - Phase 2 / Phase 3 Shortfall Assumption – 85% at Northern and Southern Zones / 100% at Wheeler Ridge
  - Updated Expansion Scenario Assumption
    - 95% RPU at Northern / Southern and Wheeler Ridge Zones
    - One Pipeline Outage Assumed – 212 MMcf/d Capacity Outage
      - 212 MMcf/d represents average capacity reduction associated with each planned/ unplanned outage that has occurred on SoCalGas system since 2015
      - Outage represented by reduction in withdrawal capacity at Playa Del Rey storage field (212 MMcf/d withdrawal capacity reduction)

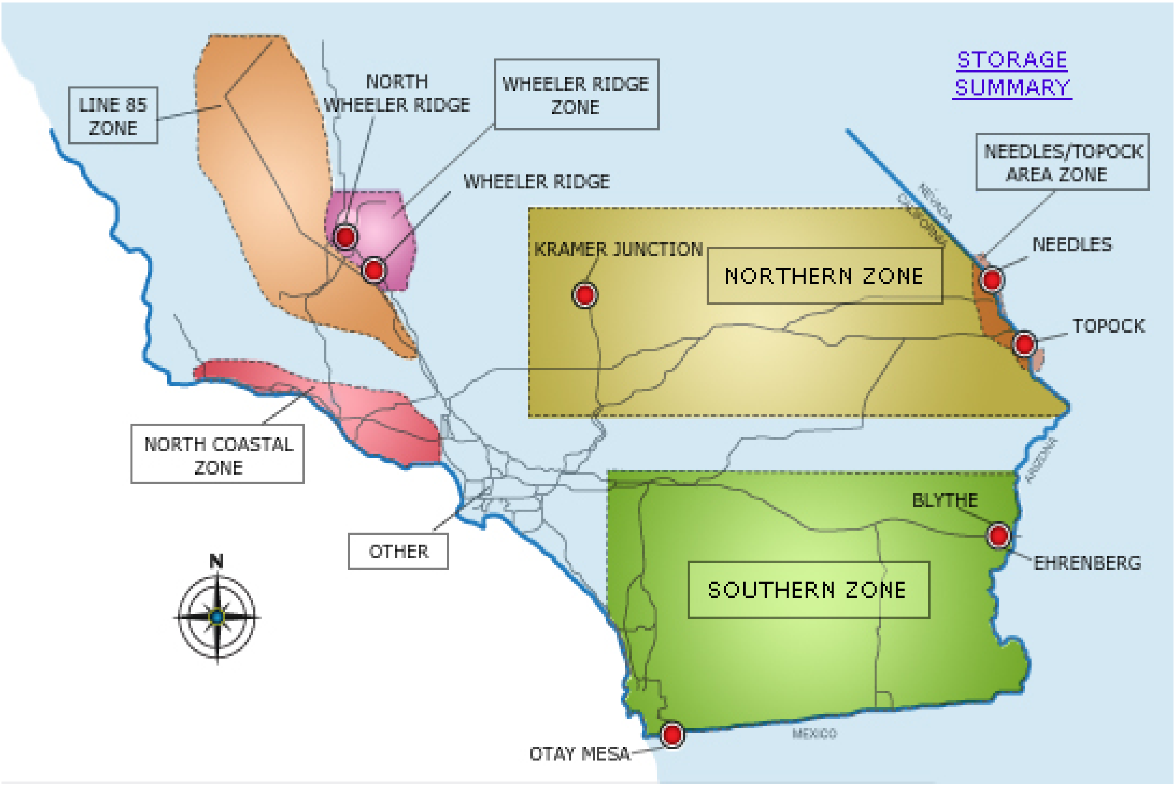
- **Storage Assumption (Used for Shortfall Analysis and in Portfolio 1 Pipeline Facility Expansion Analysis)**
  - Available Winter Peak Day Storage based upon minimum inventory during winter season as calculated in seasonal storage analysis.
    - 54% Inventory Assumption in 2027 hydraulic model
    - 82% Inventory Assumption in 2035 hydraulic model

Portfolio 1: Gas Transmission System Expansion

Detailed Assumptions: 2027 and 2035 Expansion Scenario Pre-Expansion Supply Sourcing

- **Pipeline Supply Sources**
  - Supply Sourcing in Wheeler Ridge and Northern Zones based upon 95% RPU
  - Northern Zone Facilities assumed restored to Nominal Capacity of 1,590 MMcf/d
  - Southern Zone supplies in excess of 980 MMcf/d must be sourced from Otay Mesa- as Otay Mesa is il-liquid supply market, receipts at this point remain at 50 MMcf/d

Pipeline Supply Source	Quantity (MMcf/d)
North Needles	485
South Needles (Topock)	501
Kramer Junction	525
Wheeler Ridge	727
Blythe Ehrenburg	980
Otay Mesa	50
CA Producers	70
Total – Pipeline Supply	**3,337**



Portfolio 1: Gas Transmission System Expansion

Detailed Assumptions: Storage Withdrawal Supply Sources

Winter Peak Day Hydraulic Model Withdrawal Capacity

Storage Capacity	Peak Day Withdrawals (MMcf/d)
2027 Expansion Scenario	
WD Capacity (54% Inventory)	**1,033**
Pipeline Outage Reserve	**(212)**
2027 Peak Day WD Capacity	**821**
2035 Expansion Scenario	
WD Capacity (82% Inventory)	**1,262**
Pipeline Outage Reserve	**(212)**
2035 Peak Day WD Capacity	**1,050**

Notes

- The storage Inventory assumptions (54% in 2027 and 82% in 2035) are based on the lowest projected storage inventory during the peak winter months of December thru February as projected by the FTI/GSC seasonal storage analysis presented during the Phase 3 Workshop #2 held on March 30, 2021.
- Honor Rancho storage is utilized as a balancing source in the hydraulic models (withdrawals at Honor Rancho adjust within the day to support hourly demand requirements). As a result, it is assumed that Honor Rancho can withdraw at any level between 0 MMcf/d and the maximum available withdrawal level (based upon available inventory) at any time during the peak day operation.
- In order to maintain maximum deliverability from the storage fields during the winter season, it is assumed that the Playa Del Rey storage field is operated such that inventories are maintained to maximize peak day withdrawal capacity from this field. As a result, the bulk of seasonal storage withdrawals within the seasonal storage analysis are sourced from Honor Rancho and La Goleta.

Portfolio 1: Gas Transmission System Expansion

Detailed Assumptions: Hourly Demand Profiles Utilized (Unchanged from Nov 2020)

1. As part of its Phase 2 analysis, CPUC undertook a detailed review of SoCalGas hourly profiles for core and non-core customer classes

2. Based on this review, CPUC concluded that aggregation of demand profiles across zip codes on the system validates SoCalGas core hourly profile assumption and CPUC utilized SoCalGas hourly demand profiles in its analyses

3. GSC/FTI adopted CPUC approach and utilized SoCalGas hourly profiles in its Phase 3 models of SoCalGas system

4. EG Profiles developed by FTI using PLEXOS model for years 2027 and 2035

Portfolio 1: Gas Transmission System Expansion

Detailed Assumptions: Hydraulic Model Assumptions Summary

Delivery Quantities

1. All Core and Non-Core (non EG) deliveries maintained
2. EG deliveries maintained as required in FTI-PLEXOS model

Pressures

1. System pressures maintained below MAOP
2. Delivery pressures maintained above minimum allowable operating pressures with a few isolated variances in San Joaquin Valley
3. Isolated San Joaquin Valley pressures fell below minimum allowable operating pressure by approximately 50 psig or less

Line Pack

1. Line Pack recovers over twenty-four-hour period

Supplies

1. Honor Rancho storage and Line Pack successfully utilized to balance demand variations during the day
2. Incremental supplies received at Wheeler Ridge or North Needles/ Topock
3. All other pipeline and storage receipt points held constant at planned levels

Portfolio 1: Gas Transmission System Expansion

Technical Solution: Portfolio 1a- Northern Zone Supply Expansion

2027 Expansion

Incremental Receipts

- Topock: 13 MMcf/d
- North Needles: 382 MMcf/d
- **Total: 395 MMcf/d**

Expansion Facilities

- 48.5 Miles 36" Loop Newberry towards Cajon Junction
- 20 Miles 36" Loop N Needles West
- 15 Miles 36" Loop Kelso CS West
- Expand Quigley Regulator Station

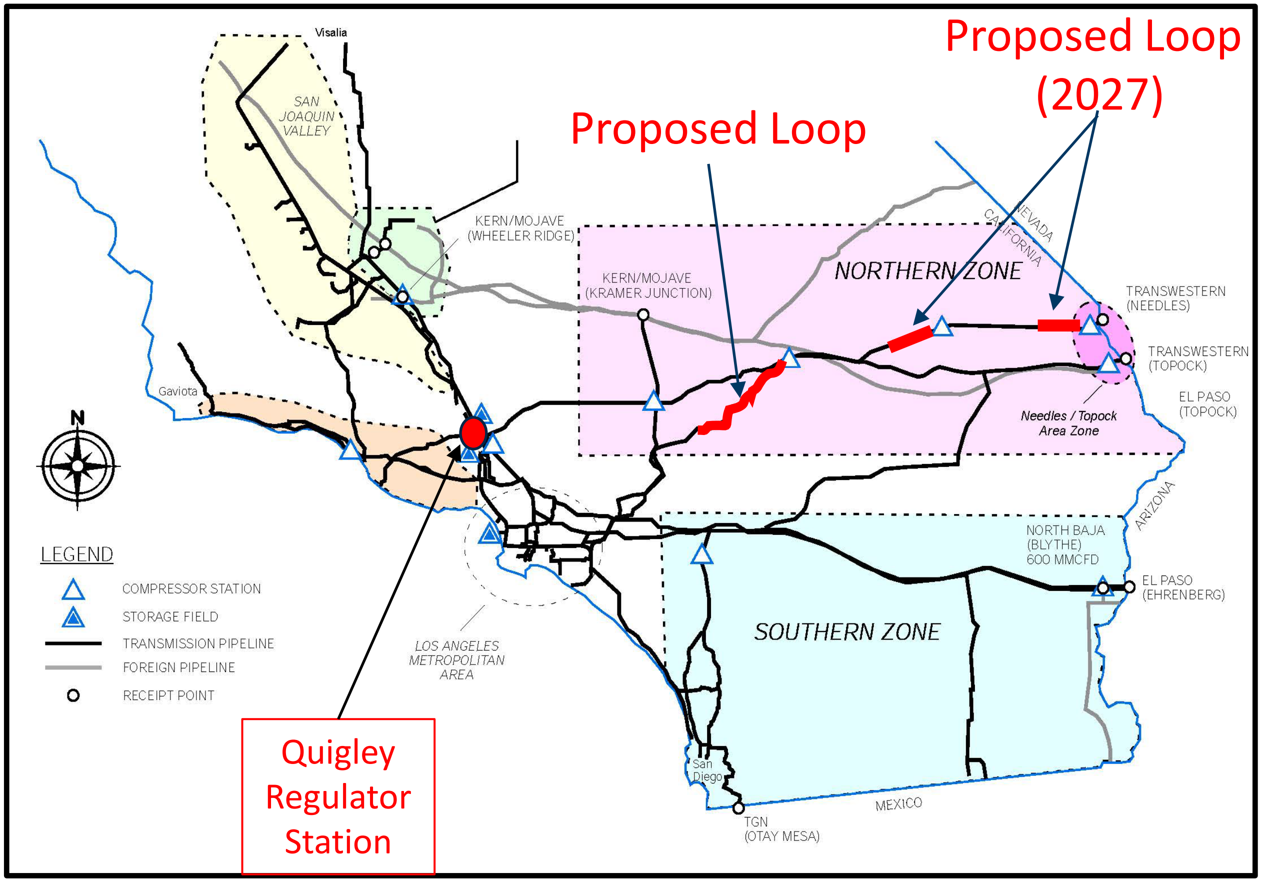
2035 Expansion

Incremental Receipts

- Topock: 13 MMcf/d
- North Needles: 300 MMcf/d
- **Total: 313 MMcf/d**

Expansion Facilities

- 41.5 Miles 36" Loop Newberry towards Cajon Junction
- Expand Quigley Regulator Station



Notes

- Pipeline "Loop" is a pipeline section laid parallel and connected to the main gas pipeline. A pipeline loop increases the flowing capacity and/or decreases the pressure loss of the system through the looped segment.
- Expansion from Northern Zone assumes incremental supplies at Needles / Topock Border Receipt Points

Portfolio 1: Gas Transmission System Expansion

Technical Solution: Portfolio 1b - Wheeler Ridge Expansion to Access CGT

2027 Expansion

Incremental Receipts

- Wheeler Ridge: 395 MMcf/d

Expansion Facilities

- 34.8 Miles 36” Loop Wheeler Ridge South
- Expand Quigley Regulator Station

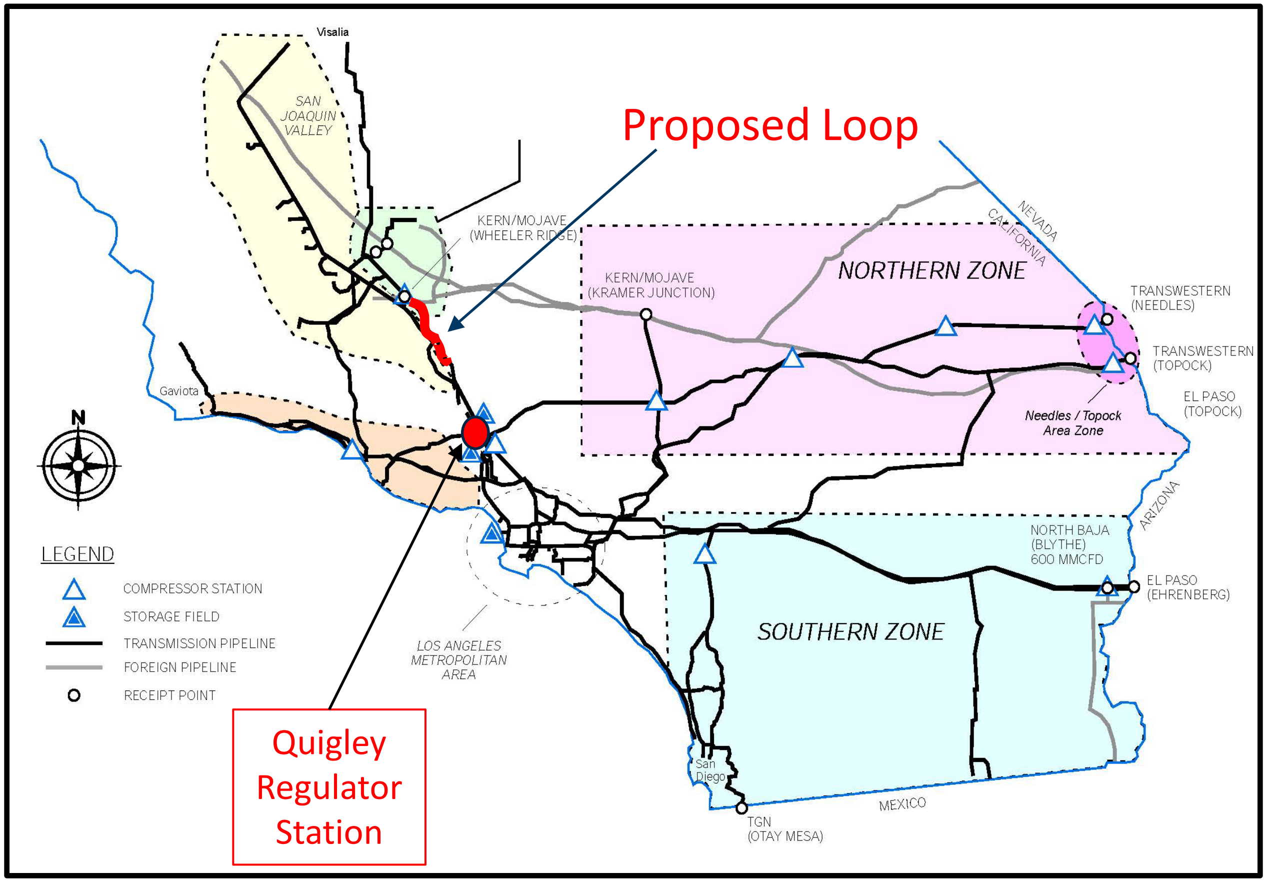
2035 Expansion

Incremental Receipts

Wheeler Ridge: 313 MMcf/d

Expansion Facilities

- 24.8 Miles 36” Loop Wheeler Ridge South
- Expand Quigley Regulator Station



Notes

- Expansion from Wheeler Ridge Assumes Incremental Storage Withdrawals from PGE Storage Points (Gill Ranch or other)

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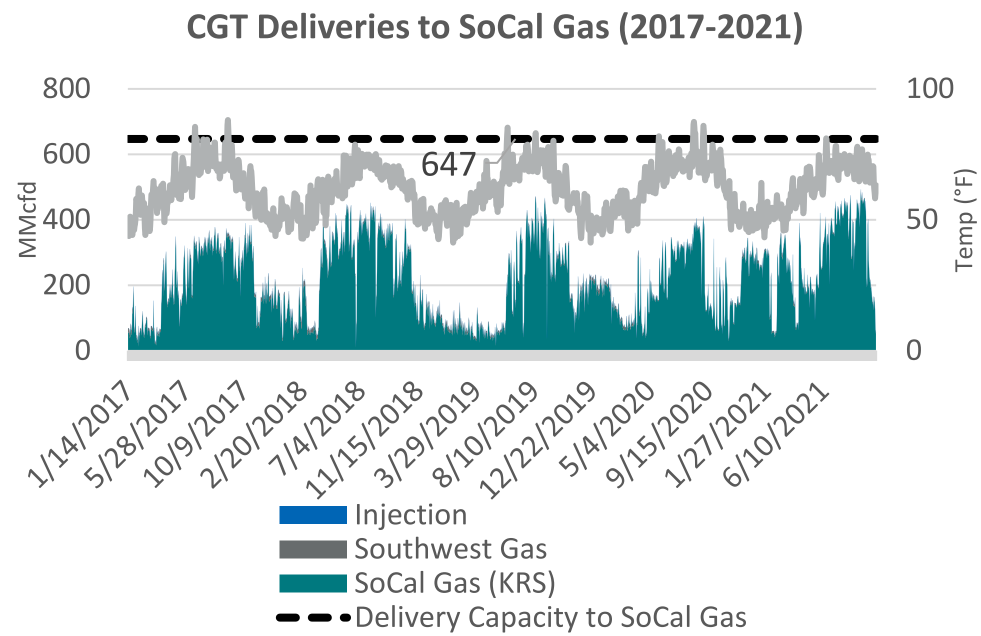
Portfolio 1: Gas Transmission System Expansion

Technical Solution: Portfolio 1b- Upstream Storage/ Transport



Discussion

1. California Gas Transmission lists delivery capacity of 647 MMcf/d to SoCalGas at the Kern River Station
2. History indicates that rarely is more than 200 MMcf/d of this capacity utilized during winter months
3. SoCalGas shortfall requires 395 MMcf/d of delivery capacity in 2027 and 323 MMcf/d in 2035
4. Capacity appears to be sufficient to support demand requirements on winter peak day

Portfolio 1: Gas Transmission System Expansion

Cost-Benefit Analysis: Portfolio 1a – Northern Zone Supply Expansion

Cost-Benefit Analysis (2019$'s in 2027)

	2027	2035
Cost	**$47,737,000**	**$20,894,000**
Levelized Annual Cost	$47,737,000	$20,894,000
Pipelines	$47,519,000	$20,703,000
Pressure Limiting Station	$218,000	$191,000
CO_2 Emissions Increase	$0	$0
Benefits	**$0**	**$0**
Gas Cost Reduction	$0	$0
Electricity Cost Reduction	$0	$0
CA CO_2 Emissions Reduction	$0	$0
Net Benefit	**-47,737,000**	**-20,894,000**
Benefit Cost Ratio	**N/A**	**N/A**

Cost-Benefit Discussion

- This portfolio's annual costs are the lowest among all portfolios
- No gas cost or electricity cost reductions (benefits) as this portfolio directly offsets Aliso Canyon; therefore, net benefits are negative
- No net CO_2 emissions as the expansion is primarily used to relieve Aliso Canyon and not utilized outside the peak day
- A 6.4% capital recovery factor from the National Renewable Energy Laboratory (NREL) 2021 Annual Technology Baseline (ATB) is used

Portfolio 1: Gas Transmission System Expansion

Cost-Benefit Analysis: Portfolio 1b – Wheeler Ridge Expansion to Access CGT

Cost-Benefit Analysis (2019$'s in 2027)

	2027	2035
Cost	**$150,287,000**	**$105,940,000**
Levelized Annual Cost	$20,022,000	$12,563,000
Pipelines	$19,804,000	$12,372,000
Pressure Limiting Station	$218,000	$191,000
Storage	$21,570,000	$15,463,000
PG&E Tariff	$108,695,000	$77,914,000
CO_2 Emissions Increase	$0	$0
Benefits	**$0**	**$0**
Gas Cost Reduction	$0	$0
Electricity Cost Reduction	$0	$0
CA CO_2 Emissions Reduction	$0	$0
Net Benefit	**-$150,287,000**	**-$105,940,000**
Benefit Cost Ratio	**N/A**	**N/A**

Cost-Benefit Discussion

- This portfolio's annual costs are the second lowest amongst all portfolios
- No gas cost or electricity cost reductions (benefits) as this portfolio directly offsets Aliso Canyon; therefore, net benefits are negative
- No net CO_2 emissions as the expansion is primarily used to relieve Aliso Canyon and not utilized outside the peak day
- A 6.4% capital recovery factor from the National Renewable Energy Laboratory (NREL) 2021 Annual Technology Baseline (ATB) is used

Portfolio 2:
Gas Demand Reduction

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Portfolio 2: Gas Demand Reduction

Overview: Three Components to Address Shortfall

Description

- The Gas Reduction Portfolio is made up of three components:
  - Building electrification, which aims to reduce gas demand both on the peak winter day and on an annual basis by converting water heating and space heating use in residential and commercial buildings to electric
  - Gas and electric energy efficiency programs that aim to reduce gas and electric use respectively
  - Non-Core Demand Response, which aims to reduce reliably gas demand by non-core, non-EG industrial customers on the peak winter day, has sufficient potential to address the remaining shortfall after accounting for electrification and energy efficiency impacts
- This portfolio is different from the others under discussion in two important respects:
  - No single component can, by itself, meet the shortfall although, when combined, they have the potential to reduce gas demand on the peak winter day by more than the shortfall
  - The cost characteristics of the components are also very different – e.g., Non-Core Demand Response is targeted at the winter peak day, while building electrification results in a permanent decrease in gas' share of building energy consumption
- Because of these differences, the cost-benefit analysis for each component was performed separately

Portfolio 2: Gas Demand Reduction

Overview: Impact on Shortfall

Inputs by Component

Building Electrification

- Level of electrification is assumed to be at the Moderate Electrification level of the CEC's 2021 California Building Decarbonization Assessment
- Hourly load shapes for displaced gas and electric demand increase developed by FTI based on temperature data and American Gas Association information on electric technology efficiency

Impact on Shortfall - 1 in 10 Winter Peak Day (MMcf/d)

	2027	2035
Projected Shortfall	395	323
Electrification & Electric Energy Efficiency	**115**	**170**
Increased Electric Generation Demand	(30)	(37)
Decreased Gas Heating Demand	145	207
Remaining Shortfall	280	153
Non-Core Demand Response Potential*	**674**	**653**

*Source: CGR; redacted work papers SCG, SDG&E; FTI analysis

Energy Efficiency

- Gas energy efficiency: Comparison of SCG and SDG&E Base Case forecasts as reported in the 2020 CGR with the TRC High Case from the 2021 Energy and Potential Goals Study prepared by Guidehouse
- Electric energy efficiency: Incremental electric energy efficiency relative to the Base Case 2019 Integrated Energy Policy Report (IEPR) based on the electric energy efficiency from the 2021 Energy and Potential Goals Study

Gas

- Base case already reflects gas energy efficiency potential

Electric

- 3,952 GWh incremental to the Base case in 2027
- 7,006 GWh incremental to the Base case in 2035

Non-Core Demand Response

- Over 650 MMcf/d potential non-core demand on peak winter peak day available for demand response in 2027 and 2035, estimated based on the CGR
- FTI estimated cost of stand-alone, on-site small-scale LNG plant estimated to serve as proxy for cost of achieving demand response
- Potentially could cover entire shortfall, but has to be confirmed via a reverse auction

Portfolio 2: Gas Demand Reduction

Building Electrification: Gas Demand Reduction Under Alternate Scenarios

		2030			Notes
		Minimal Electrification	Moderate Electrification	Aggressive Electrification	
California	Gas demand *MMTherms*	2,870	2,270	1,025	*CEC Report Fig 26.*
	Conversion to electricity, *MMTherms*	980	1,580	2,825	
	Conversion to electricity, *MMcf/d*	261	420	751	
	SCG & SDG&E share	57%	56%	55%	
SDG&E AND SCG	**2030 Conversion to Electricity, *MMcf/d***	**150**	**236**	**413**	
	Residential HVAC	37	59	62	*Calculated based on Fig 27,28 and 29*
	Commercial HVAC	18	28	50	
	Residential Waterheat	46	68	66	
	Commercial Waterheat	6	7	17	
	Subtotal	108	$\boxed{163}$	194	
	All Other	42	73	219	
	2027 Conversion to Electricity, MMcf/d	**105**	**165**	**289**	*Interpolated*
	Break-out by electric end-use, *MMcf/d*				Calculated based on Fig 27,28 and 29
	Residential HVAC	26	41	43	
	Commercial HVAC	13	20	35	
	Residential Waterheat	32	48	46	
	Commercial Waterheat	4	5	12	
	Subtotal	75	$\boxed{114}$	136	
	All Other	29	51	153	

Source: CEC; FTI Analysis

Notes

- CEC Report provides a basis to estimate the amount of 2020 gas combustion that is lost to building electrification in SCG and SDG&E under three scenarios and four applications: residential HVAC, residential water heating, commercial HVAC, and commercial water heat
- Efficient Aggressive Electrification is no different from Aggressive Electrification with respect to gas use

Portfolio 2: Gas Demand Reduction

Building Electrification: Electric Demand Increase Under Alternate Scenarios

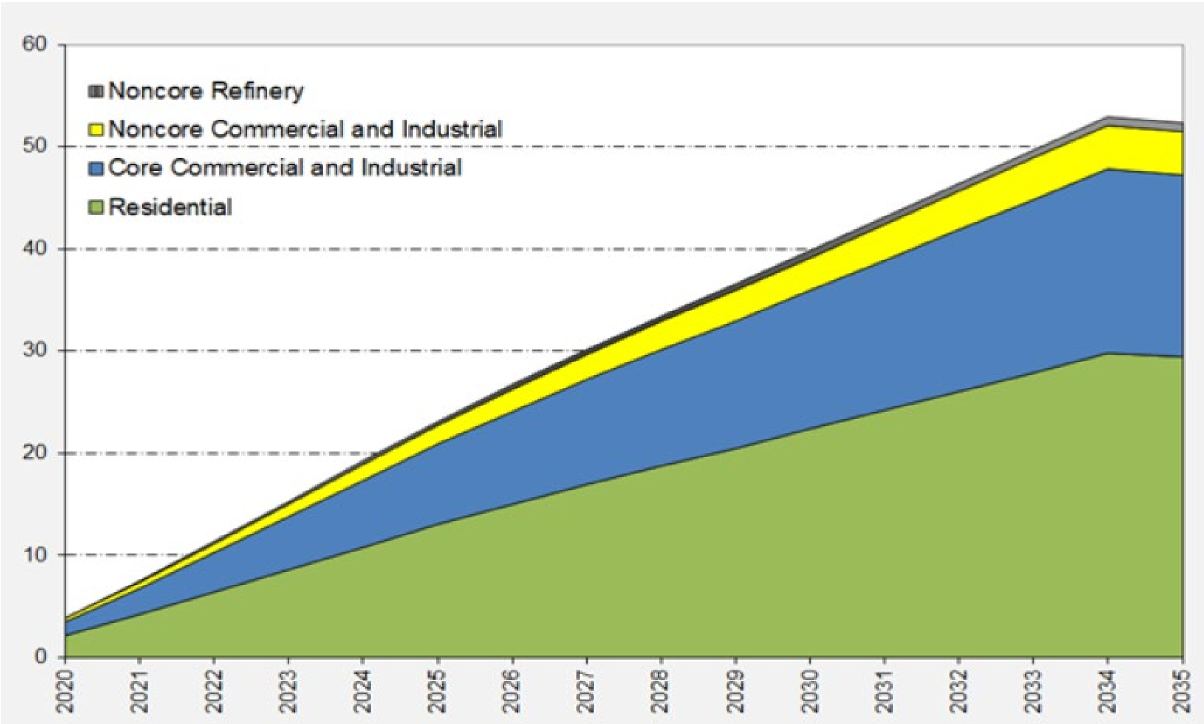
		2030				Notes
		Minimal Electrification	Moderate Electrification	Aggressive Electrification	Efficient Aggressive Electrification	
California	Gas combustion (SCG+SDG&E), *MMTherms*	2,870	2,270	1,025	1,025	*CEC Report Fig 26.*
	Conversion to electricity, *MMTherms*	980	1,580	2,825	2,825	*Calculated*
	Increase in Electricity Total California, GWh	11,667	22,885	47,595	38,639	*CEC Report Fig 20, 21, 22 and 23*
	SCG & SDG&E share	57%	56%	55%		*Calculated*
SDG&E AND SCG	**2030 Increase in Electricity, GWh**	**6,697**	**12,846**	**26,177**		*Calculated based on Fig 20, 21, 22 and 23*
	Residential HVAC- heat	1,473	2,569	5,759	-	
	Residential HVAC- cool	402	642	1,571	-	
	Commercial HVAC	670	1,028	1,832	-	
	Residential Waterheat	2,411	5,138	10,733	-	
	Commercial Waterheat	469	771	1,047	-	
	Subtotal	5,425	$\boxed{10,148}$	20,942		
	All Other	1,272	2,698	5,235	-	
	2027 Increase in Electricity, GWh	**5,504**	**9,156**	**12,732**		*Interpolated*
	Residential HVAC- heat	1,211	1,831	2,801		
	Residential HVAC- cool	330	458	764		
	Commercial HVAC	550	732	891		
	Residential Waterheat	1,981	3,662	5,220		
	Commercial Waterheat	385	549	509		
	Subtotal	4,457	$\boxed{7,232}$	10,185		
	All Other	1,046	1,923	2,546		

Source: CEC; FTI Analysis

Portfolio 2: Gas Demand Reduction

Energy Efficiency/Gas: The Base Case Reflects Robust Gas Energy Efficiency

SCG Projections of Energy Efficiency in California Gas Report, Bcf



SCG Redacted Work Papers; CGR; FTI Analysis

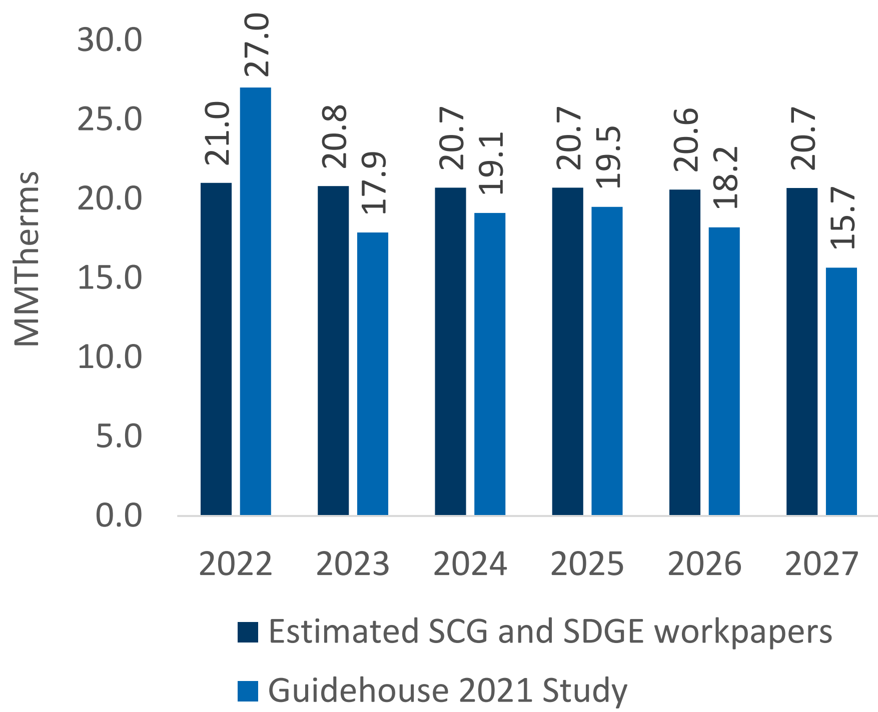
Discussion

- SCG's projections reflect substantial energy efficiency in total – close to 13% of consumption by 2035 or 56 Bcf/year
- The gas energy efficiency attributable to "EE Incentive Programs" as distinct from components such as Codes & Standards is between 45% and 50% of the total depending on year.

Portfolio 2: Gas Demand Reduction

Energy Efficiency/Gas: Base Case Levels of Energy Efficiency Comparable to 2021 Guidehouse

Incremental Annual Energy Efficiency Incentive Program Comparison



Discussion

- SCG and SDG&E projections of Energy Efficiency Incentive Programs total 103.5 MMTherms between 2022 and 2027 (~10 Bcf)
- Guidehouse TRC High Case on a comparable basis is 90.4 MMTherms (~8.8 Bcf)

Notes

1) Guidehouse TRC High Case based on reported results in 2021 Energy Efficiency and Potential Goals Study
2) Guidehouse EE Incentive Programs results only available 2022 onwards
3) Guidehouse measure type limited to Energy Efficiency Incentive Programs

Portfolio 2: Gas Demand Reduction

Electric Energy Efficiency: Adjusted Upwards to 2021 Guidehouse Level

Comparison of Energy Efficiency Levels

Case	2027 GWh	2035 GWh	Source
Base Case – Net Energy for Load	325,962	351,043	2019 IEPR, California-wide
Base Case – Electric Energy Efficiency included	23,493	48,627	2019 IEPR, California-wide
Gas Reduction Portfolio – incremental electric energy efficiency	3,952	7,006	2021 Guidehouse study for the three CA jurisdictional utilities

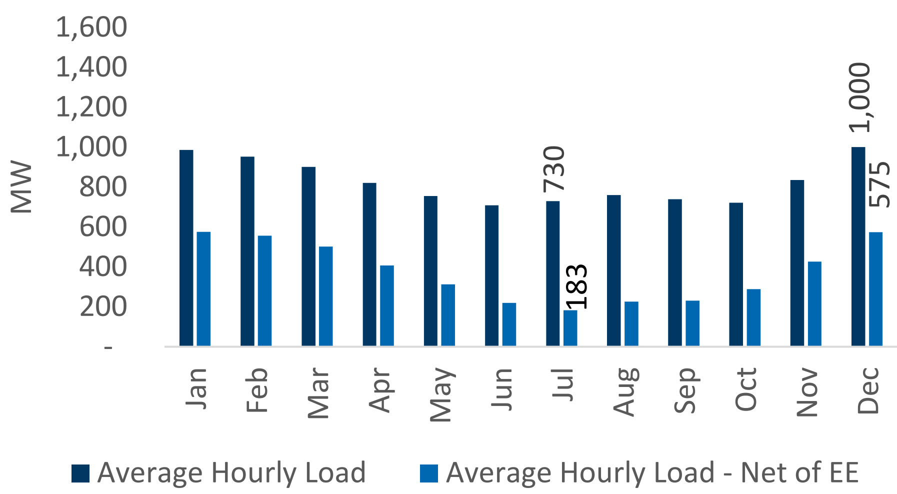
Discussion

- Base Case reflects 2019 IEPR level of demand, which includes forecasted energy efficiency in the forecast
- The projected electric energy efficiency under the 2021 Guidehouse TRC High Case for the three jurisdictional electric utilities is assumed to be incremental to the 2019 IEPR

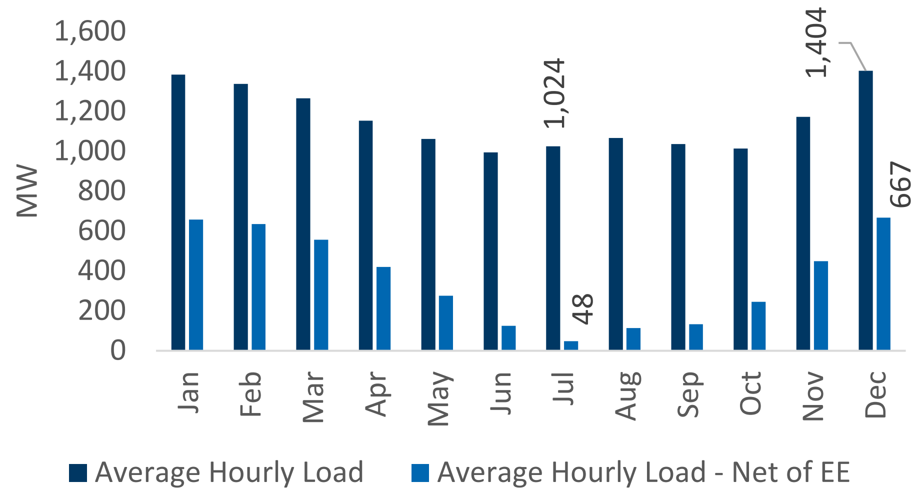
Portfolio 2: Gas Demand Reduction

Energy Efficiency/Electric: Implication of Incremental Energy Efficiency on Southern California Load

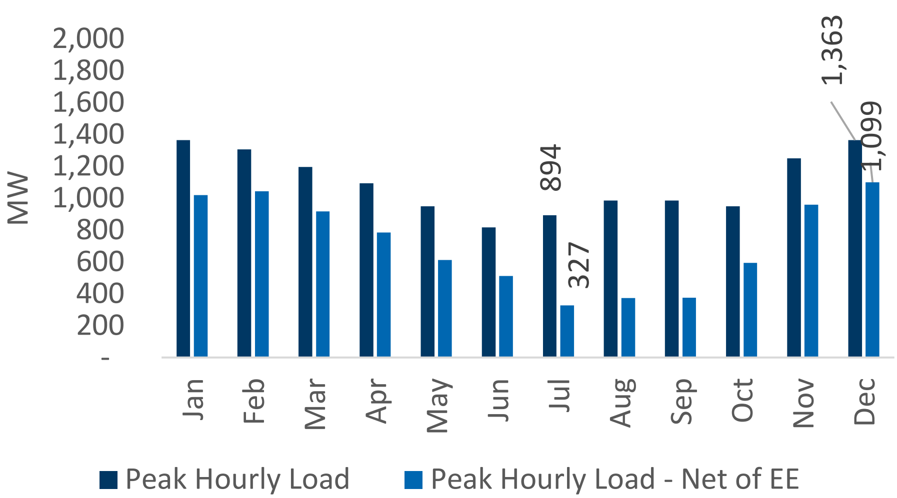
Average Hourly Load - 2027



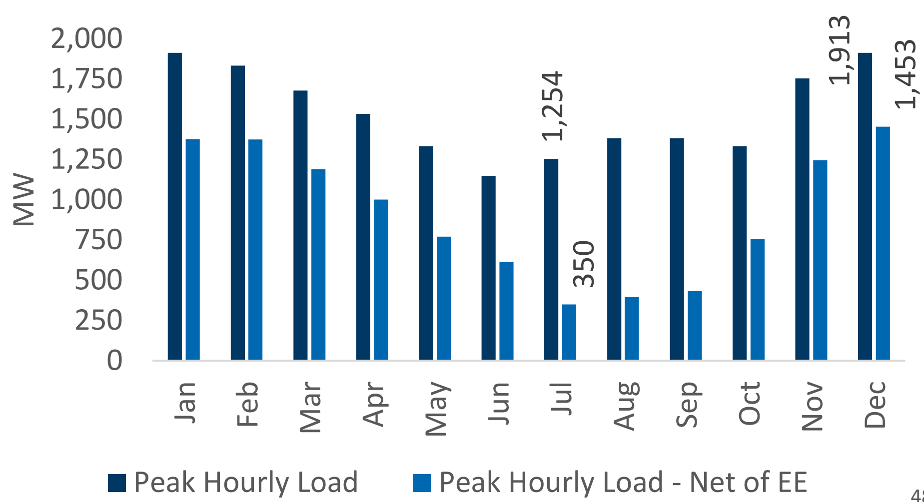
Average Hourly Load - 2035



Peak Hourly Load - 2027



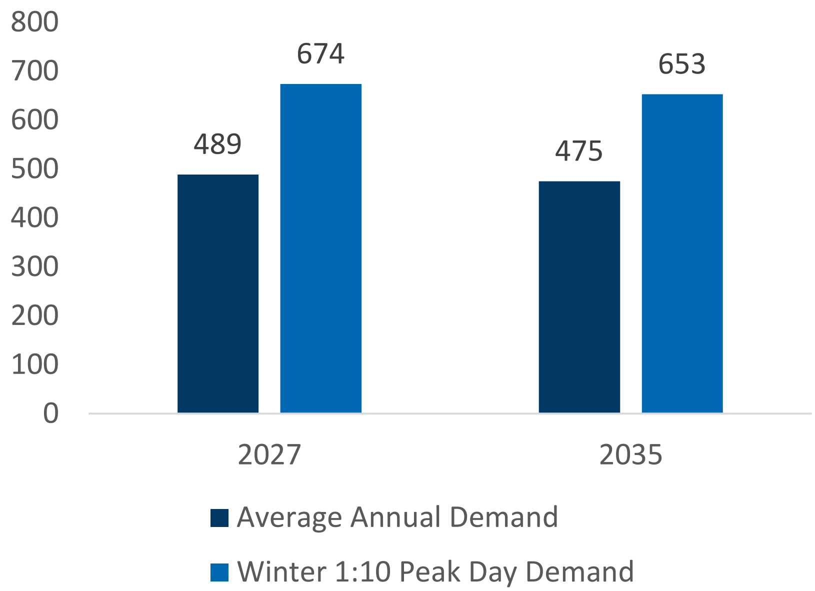
Peak Hourly Load - 2035



Portfolio 2: Gas Demand Reduction

Industrial Demand Response: Potentially Displaceable Non-Core Demand is Significant

Non-Core Peak Demand (MMCFD)



Source: CGR; redacted work papers SCG, SDG&E; FTI analysis

- Non-Core demand, which includes large refineries served by the SCG gas system, offer over 670 MMFCD of potentially displaceable demand in 2027
- The Non-Core Demand Response program would conduct an auction in which individual facilities would have the opportunity to enter into binding agreements to reduce demand during the winter peak day, when requested, in exchange for payments required. Key elements would include:
  - Metering of facility gas use with direct load control capability
  - Contractually specified notice provisions to request reduction
  - Flexibility for facility to determine how to meet its commitment to reduce
  - SCG right to reduce gas flows in the event of inadequate compliance when requested or when necessary to maintain system reliability
  - Agreed-upon reservation and performance payments for reduction
- Additional potentially displaceable demand could be made available in the form of expanded Demand Response programs targeted at Core Commercial and Industrial customers

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Portfolio 2: Gas Demand Reduction

Costs: Building Electrification- Cost Under Alternate Scenarios

Discounted Net Costs, 2019$ millions*

	California	SCG and SDG&E	SCG and SDG&E Space Heating/Cooling and Water Heating		
	2030	2030	2030	2027 (Interpolated)	2035
Minimal Electrification	2,845	1,593	1,274	1,047	1,274
Moderate Electrification	6,160	3,449	2,760	1,967	2,760
Aggressive Electrification	37,401	20,945	16,755	8,149	16,755
Efficient Aggressive Electrification	39,460	22,097	17,769	8,599	17,679

Source: CEC; FTI Analysis

- Moderate Electrification selected as the basis for this study because cost of aggressive electrification would make the option unattractive is benefit-cost calculation
- CEC modeled only 2030:
  - 2027 estimate is based on simple interpolation between 2020 actual and 2030 forecasted
  - 2035 electrification level assumed to be same as 2030

* Under the CEC methodology, the net cost reflects the direct technology cost for electrification - equipment, installation labor cost, panel costs (if applicable), and profit margin. The net cost also includes the avoided gas operating costs and the incurred electricity consumption costs.

Portfolio 2: Gas Demand Reduction

Costs: Natural Gas and Electric Energy Efficiency

Estimated Costs of Energy Efficiency

Energy Efficiency	California-wide Incremental to Base Case*			
Gas	Not applicable-- Base Case reflects TRC High Case levels			
Electric	Incremental to Base Case, GWh	Incremental Cost, $ million	Incremental Benefit, $ million**	Net Benefit, $ million
2027	3,952	$417	$1,181	$764
2035	7,006	$575	$2,022	$1,447

* For perspective, total Base Case California load exclusive of demand modifiers is 262,740 GWh in 2027 and 271,584 GWh in 2035

** The 2021 Guidehouse study uses a price per ton of carbon of $161.84 in 2027 and $292.53 in 2035 (in nominal $)

Discussion

- 2021 Guidehouse study, TRC High Case:
  - Benefits exceed costs (sum of program and administrative costs), driven mainly by high GHG reduction benefits – i.e., a high carbon price**
  - Because of its forecasted benefits, the incremental electric energy efficiency under this case is applied in the Gas Reduction Portfolio at no cost

Portfolio 2: Gas Demand Reduction

Costs: Industrial Demand Response – LNG-Cost Parity

Projects Analyzed

Plant Name/Location	Output (MMcf/d)	Reported Cost ($mm)	Reported Cost ($mm/MMcf/d)	Onsite LNG Storage (mm gallons)	Estimated Days of Storage
Passyunk Energy Center, Philadelphia	10.0	$60.0	6.00	3.0	25
National Grid, Charlton Mass	20.8	$100.0	4.81	2.0	8
Tacoma LNG, Tacoma Washington	66.0	$226.8	3.44	6.3	8
FTI estimate (scaled to 50 MMcf/d)*	**50.0**	**$180.9**	**3.62**	**4.8**	**8**

* Assumed approximate, average size used for a peak shaving plant is 50 MMcf/d by industrials

Portfolio 2: Gas Demand Reduction

Cost-Benefit Analysis: Electrification & Electric EE Results

Cost-Benefit Analysis (2019$'s in 2027)

	2027	2035
Cost	**$176,854,000**	**$175,751,000**
Levelized Annual Cost	$126,446,000	$155,512,000
Electrification	$126,446,000	$155,512,000
Electric Energy Efficiency	$0	$0
CO_2 Emissions Increase - Power	$50,408,000	$20,239,000
Benefits	**$116,315,000**	**$145,787,000**
Gas Cost Reduction	$0	$0
Electric Energy Efficiency	$0	$0
CA CO_2 Emissions Reduction – Gas	$116,315,000	$145,787,000
Net Benefit	**-$60,539,000**	**-$29,964,000**
Benefit Cost Ratio	**0.66**	**0.83**

Cost-Benefit Discussion

- Projected Energy Efficiency costs from the Guidehouse 2021 Energy Efficiency Potenial and Goals study are omitted from this portfolio analysis due to significant differences in underlying assumptions used by Guidehouse in developing its report
  - — FTI analysis assumes Social Cost of Carbon of $51/tonne
  - — Guidehouse report assumes costs ranging from $90/tonne - $300/tonne through 2035

Portfolio 2: Gas Demand Reduction

Cost-Benefit Analysis: Non-Core Demand Response Results

Cost-Benefit Analysis (2019$'s in 2027)

	2027	2035
Cost	**$107,011,000**	**$76,707,000**
Levelized Annual Cost	$107,011,000	$76,707,000
Non-Core Demand Response	$107,011,000	$76,707,000
CO_2 Emissions Increase - Power	$0	$0
Benefits	**$0**	**$0**
Gas Cost Reduction	$0	$0
Electricity Cost Reduction	$0	$0
CA CO_2 Emissions Reduction – Gas	$0	-$0
Net Benefit	**-$107,011,000**	**-$76,707,000**
Benefit Cost Ratio	**N/A**	**N/A**

Cost-Benefit Discussion

- Non-Core Demand Response individual cost evaluation assumes entire shortfall met with Demand Response
- Per unit cost estimates based on cost parity with hypothetical LNG facility are comparable to other gas utility projections of costs for similar demand response programs
  - FTI analysis indicates approximate cost per unit of reduction between $240K/MMCFD and $270K/MMCFD
  - National Grid's (NY) 2020-2021 Expanded Demand Response Implementation Plan indicates for direct load control program targeted at large C&I customers, approximate cost per unit of reduction is between $230K/MMCFD and $275K/MMCFD

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Portfolio 2: Gas Demand Reduction

Cost-Benefit Analysis: Combined Results

Cost-Benefit Analysis (2019$'s in 2027)

	2027	2035
Cost	**$252,710,000**	**$212,086,000**
Levelized Annual Cost	$202,302,000	$191,847,000
Electrification	$126,446,000	$155,512,000
Electric Energy Efficiency	$0	$0
Non-Core Demand Response	$75,856,000	$36,335,000
CO_2 Emissions Increase - Power	$50,408,000	$20,239,000
Benefits	**$116,315,000**	**$145,787,000**
Gas Cost Reduction	$0	$0
Electricity Cost Reduction	$0	$0
CA CO_2 Emissions Reduction – Gas	$116,315,000	$145,787,000
Net Benefit	**-$136,395,000**	**-$66,299,000**
Benefit Cost Ratio	**0.46**	**0.69**

Cost-Benefit Discussion

- This portfolio's annual costs are the second highest among all portfolios.
- Include a 6.4% capital recovery factor from the National Renewable Energy Laboratory 2021 Annual Technology Baseline
- Electricity cost increase (wholesale cost to load) is from PLEXOS
- CO_2 emissions
  - CA and imports
  - Uses Social Cost of Carbon of $51/tonne
- No gas cost or electricity cost reductions as this portfolio directly offsets Aliso
- Currently the lowest benefit-cost ratio among portfolios primarily due to electrification
- A minimal electrification and a larger demand response solution would be a cheaper alternative

Portfolio 3:
Generator Additions

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Portfolio 3: Generator Additions

Overview: Approach to Generator Additions

Approach

1. Exclude hybrid solar and standalone solar resources from the (TPP + 11.5 GW Procurement Order) mixture shown to the right
2. Separate hybrid wind into wind and 4h storage
3. Convert from NQC to nameplate capacity using appropriate ELCC values
4. Find each component's share of the overall portfolio
5. Using generation profiles, back-solve for the portfolio of assets that provides generation equal to the electricity shortfall in the most constrained hour while keeping relative shares constant

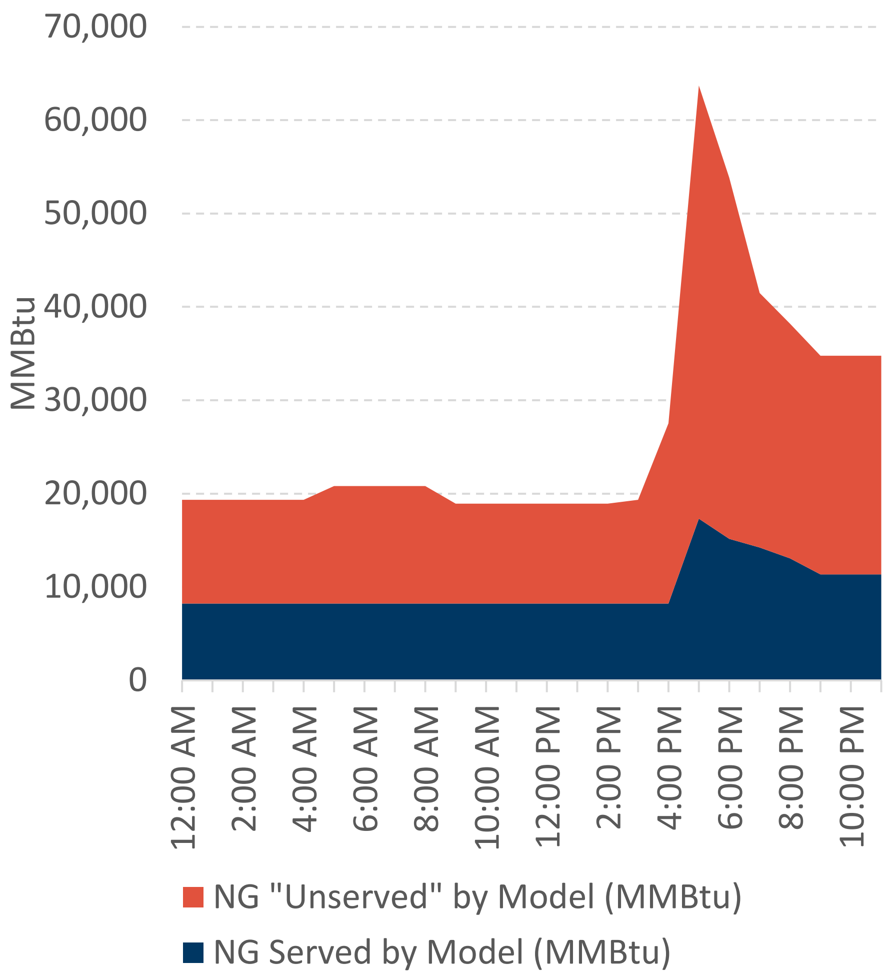
Base Case Electric Additions

Resource	Capacity (MW of NQC)	Capacity Share (% of NQC)
Hybrid (Solar + 4h Storage)	4,756	41.4%
Hybrid (Wind + 4h Storage	1,814	15.8%
Geothermal	1,000	8.7%
8h Storage	1,000	8.7%
Gas	--	0.0%
4h Storage	2,598	22.6%
Solar	75	0.7%
Wind	257	2.2%
Total	**11,500**	**100.0%**

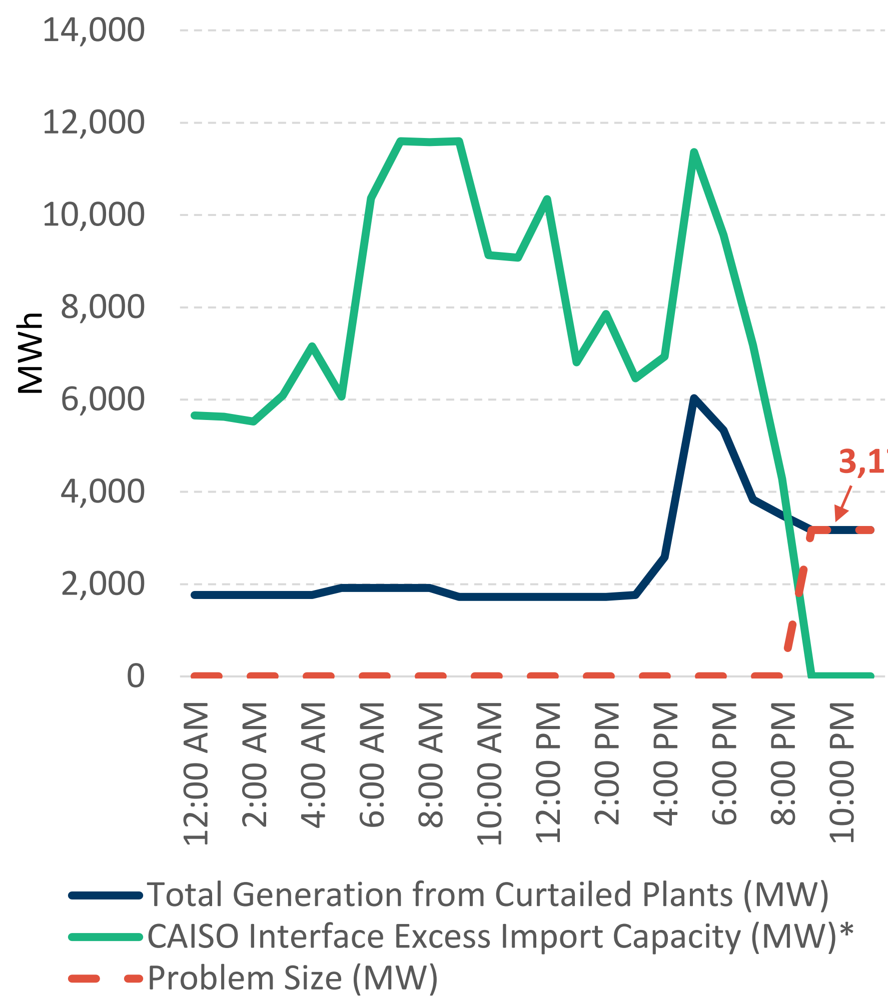
Portfolio 3: Generator Additions

Sizing generator additions to the most constrained hour in 2027

Natural Gas Shortfall by Hour on Peak Day in 2027



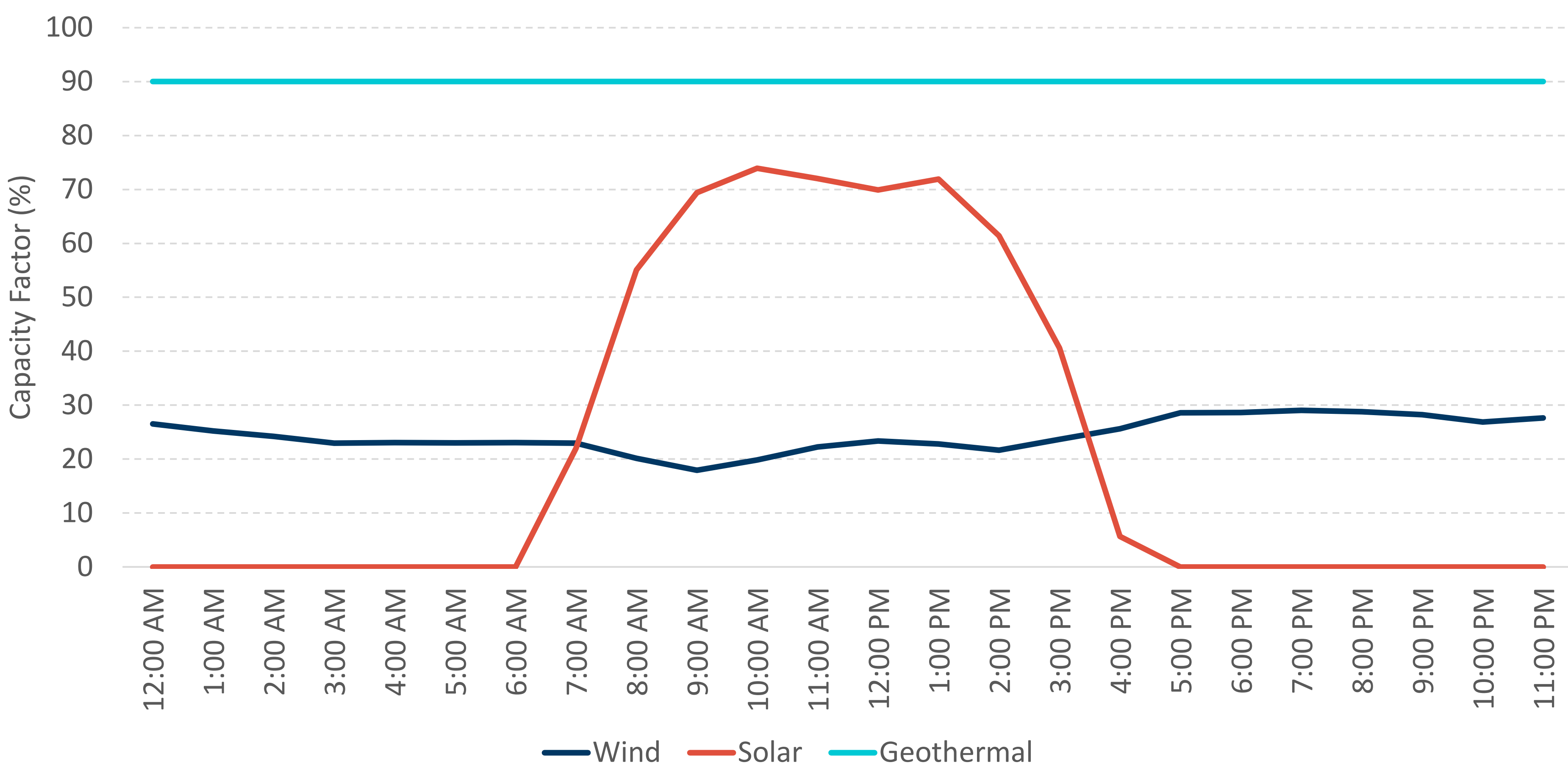
Electric "Problem Size" by Hour on Peak Day in 2027



Portfolio 3: Generator Additions

Generation Profiles of Wind, Solar, and Geothermal

Wind, Solar, and Geothermal Capacity Factors on Peak Day



Notes

- Wind capacity factor assumptions from the National Renewable Energy Laboratory Wind Integration National Dataset Toolkit
- Geothermal capacity factor assumptions from the National Renewable Energy Laboratory 2021 Annual Technology Baseline Workbook
- Solar capacity factor assumptions from the National Renewable Energy Laboratory System Advisor Model

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Portfolio 3: Generator Additions

Technical Solution: Incremental Electricity Additions for 2027 and 2035

2027 Electricity Additions to Meet Shortfall

Resource	Capacity (Nameplate MW)	Capacity Share (% of Nameplate)	Contrib. to Peak Hour (MW)
Hybrid (Solar + 4h Storage)			
Hybrid (Wind + 4h Storage			
Geothermal	460	10.6%	368
8h Storage	409	9.4%	409
Gas			
4h Storage	1,968	45.4%	1,968
Solar			
Wind	1,497	34.5%	431
Total	**4,335**		**3,176**

2035 Electricity Additions to Meet Shortfall

Resource	Capacity (Nameplate MW)	Capacity Share (% of Nameplate)	Contrib. to Peak Hour (MW)
Hybrid (Solar + 4h Storage)			
Hybrid (Wind + 4h Storage			
Geothermal	416	10.6%	370
8h Storage	370	9.4%	370
Gas			
4h Storage	1,781	45.4%	1,781
Solar			
Wind	1,355	34.5%	390
Total	**3,923**		**2,875**

Notes:

- The generation mix above reflects the mix of the (TPP + 11.5 GW procurement order) mix, excluding solar.
- Solar capacity was excluded as the peak MW shortfall occurs at night.
- Hybrid wind is shown separated into its component parts (Wind and 4h Storage) for clarity.
- Geographic dispersion of generating resources is based on the 11.5 GW procurement order load-serving entity requirements.
- Capacity values shown are nameplate, rather than NQC, as ELCCs change when adding additional capacity to a system.

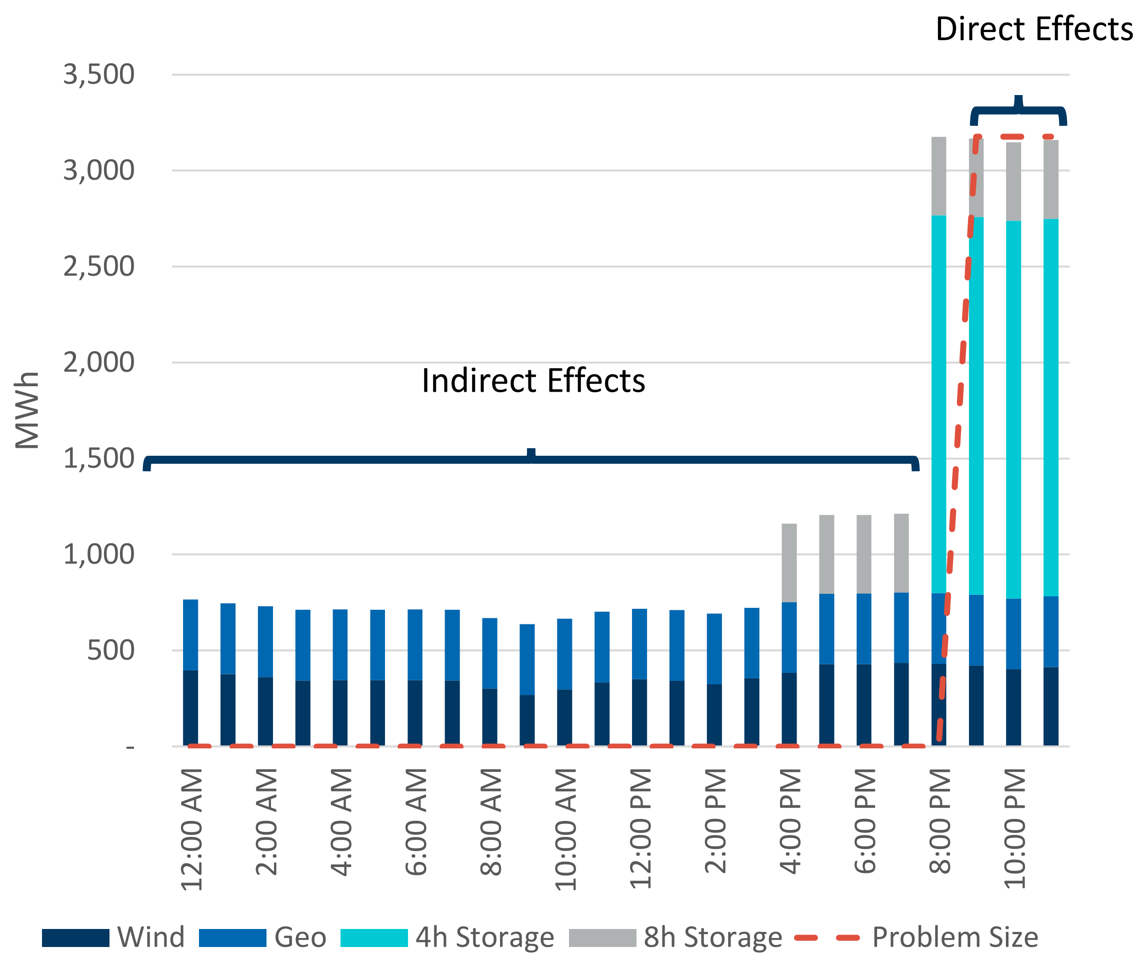
Portfolio 3: Generator Additions

Generation Profiles of Wind, Solar, and Geothermal

Discussion

- Direct Effects
  - The generation portfolio addresses the unserved gas generation during the most problematic hours of 9:00 PM – 11:00 PM.
- Indirect Effects
  - The additional zero marginal cost generation from this portfolio displaces gas generation from 12:00 AM to 8:00 PM.
  - This “frees up” the limited amount of gas available to the electric generation sector to be used most efficiently throughout the day.

Generation from 2027 Generator Additions



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Portfolio 3: Generator Additions

Modeling Inputs: Generator Additions; Cost Inputs

2027 Cost and Performance Characteristics

Technology	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-y)	Variable O&M ($/MWh)	Capacity Factor
Wind	1,497	$1,083	$40.1	$0.00	35.0%
Geothermal	460	$5,833	$130.4	$0.00	90.0%
4Hr Battery Storage	1,968	$1,092.31	$27.31	$0.00	Modeled
Pumped Storage (10 hr. duration)	409	$3,767	30.03	$0.00	Modeled

2035 Cost and Performance Characteristics

Technology	Capacity (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-y)	Variable O&M ($/MWh)	Capacity Factor
Wind	1,355	$903	$37.5	$0.00	35.0%
Geothermal	416	$5,413	$127.6	$0.00	90.0%
4Hr Battery Storage	1,781	$980.89	$24.52	$0.00	Modeled
Pumped Storage (10 hr. duration)	370	$2,141.06	$53.53	$0.00	Modeled

Note: Wind, geothermal, and battery storage (4-hr.) cost data are from the National Renewable Energy Laboratory 2021 Annual Technology Baseline Workbook; pumped storage cost data is from the Pacific Northwest National Laboratory 2020 Grid Energy Storage Technology Cost and Performance Assessment report; wind and geothermal capacity factor assumptions from the National Renewable Energy Laboratory Wind Integration National Dataset Toolkit and National Renewable Energy Laboratory 2021 Annual Technology Baseline Workbook respectively.

Portfolio 3: Generator Additions

Cost-Benefit Analysis: Generator Additions; Cost-Benefit Results

Cost-Benefit Analysis (2019$'s in 2027)

	2027	2035
Cost	**$636,794,000**	**$567,831,000**
Levelized Annual Cost	$636,794,000	$567,831,000
Wind*	$101,084,000	$169,149,000
Geothermal	$235,344,000	$175,707,000
Energy Storage (4 hr.)	$190,245,000	$135,532,000
Pumped Storage (10 hr.)	$110,121,000	$87,443,000
Benefits	**$609,459,000**	**$681,550,000**
Gas Cost Reduction	$26,663,000	$19,785,000
Electricity Cost Reduction	$385,577,000	$507,645,000
Resource Adequacy Increase	$133,831,000	$106,194,000
CA CO2 Emissions Reduction	$63,388,000	$47,926,000
Net Benefit	**-27,335,000**	**113,719,000**
Benefit Cost Ratio	**0.96**	**1.20**

*Assumes Production Tax Credit (PTC) available for 2027 in-service date but not 2035.

Cost-Benefit Discussion

- This portfolio's annual cost is the highest across all portfolios.
- Benefit-Cost ratio is approximately 1
- Electricity cost reduction (wholesale cost to load) is from PLEXOS
- Resource adequacy benefit is based on CPUC-reported RA prices
- CO_2 emissions
  - Includes CA and transmission imports
  - Uses Social Cost of Carbon of $51/tonne
- Gas cost reduction is from GPCM

Portfolio 4:
Transmission Additions

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Portfolio 4: Transmission Additions

Overview: Transmission Additions to Address Shortfall

Context

- This portfolio analyzes increases in transfers from outside California into California as a solution for the shortfall on the 1 in 10 winter day.
- Consistent with the modeling inputs used in the IRP process, the Base Case reflects:
  - Specific BA to BA transmission limits, based on the SERVM inputs in the IRP modeling
  - A CAISO interface limit of 11,600 MW for the total transmission from outside CAISO into CAISO for all periods of the year (also referred to as CAISO Maximum Import Capability)
- In the Base Case, FTI's analysis showed the CAISO interface limit to be binding on the winter peaks day, which means that solutions under this portfolio must increase the CAISO interface limit.
- Quantifying the impact of transmission additions on the interface limit into CAISO requires power flow modeling and CAISO has confirmed that such a study requires a multi-year process to establish a revised interface limit
- Therefore, the solutions evaluated here must be viewed as a "what if" change to the transmission system rather than as an identifiable transmission change. For the same reason, the cost attributed to the transmission is characterized in terms of a generic $/kW.
- Given the long lead times associated with major transmission additions the solution is considered as meaningful only by 2035.

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Portfolio 4: Transmission Additions

Technical Solutions: Transmission Expansion Solutions

Two transmission expansion solutions were examined

1 Increasing CAISO Interface Limit

- This solution incorporate an increase in CAISO interface limit by 2035
- The magnitude of the increase in transmission limit is exactly equal to the Base Case 2035 gas shortfall of 2,849 MW
- During the peak winter period – three 24-hour cycles in winter including the critical day, the allowed gas burn for affected Southern California plants is limited to 468 MMCF on a daily basis – i.e., the Base Case shortfall
- All other modeling inputs are the same as the Base Case

2 Increasing AZ to LADWP + CAISO Interface Limit

- This solution incorporates an increase in the Base Case transmission limits by 2035
- The magnitude of the increase in transmission is made up of two parts:
  - Increase in the CAISO interface limit of 1,000 MW, and
  - Increase in the Arizona to LADWP (not in CAISO) of 1,000 MW
- The assumption is that an increase of imports from Arizona into a LADWP, a non-CAISO BA, will have no impact on the CAISO interface limit, which cannot be confirmed without a power flow study
- All other modeling inputs are the same as the Base Case

Portfolio 4: Transmission Additions

Modeling Inputs: Economic Cost Inputs

Technology	Capacity (MW)	kV	Length (miles)	Cost (million $'s)	Estimated Cost Year	Capex (2019$/kW)
Ten West	969	500	114	365	2018	377
Southwest Intertie Project	2000	500	275	525	2018	263
One Nevada Line	800	500	231	552	2013	690
North Gila	1250	500	97	291	2018	233
Desert Link	200	500	60	144	2015	720
GreenLink North and GreenLink West	1525	525	319	2538	Multiple Years	1664
Pacific Transmission Expansion Project	2000	500	230	1850	2020	925
Average						**696**

Notes

- The capacity increase attributable to a transmission project in MW is situation-specific and depends on dynamic factors such as the loading on different lines in the network. Nevertheless a $/kW metric is meaningful for the "what if" economic calculations of this portfolio.
- The solutions presented in Portfolio 4 do not have a directly comparable transmission project.

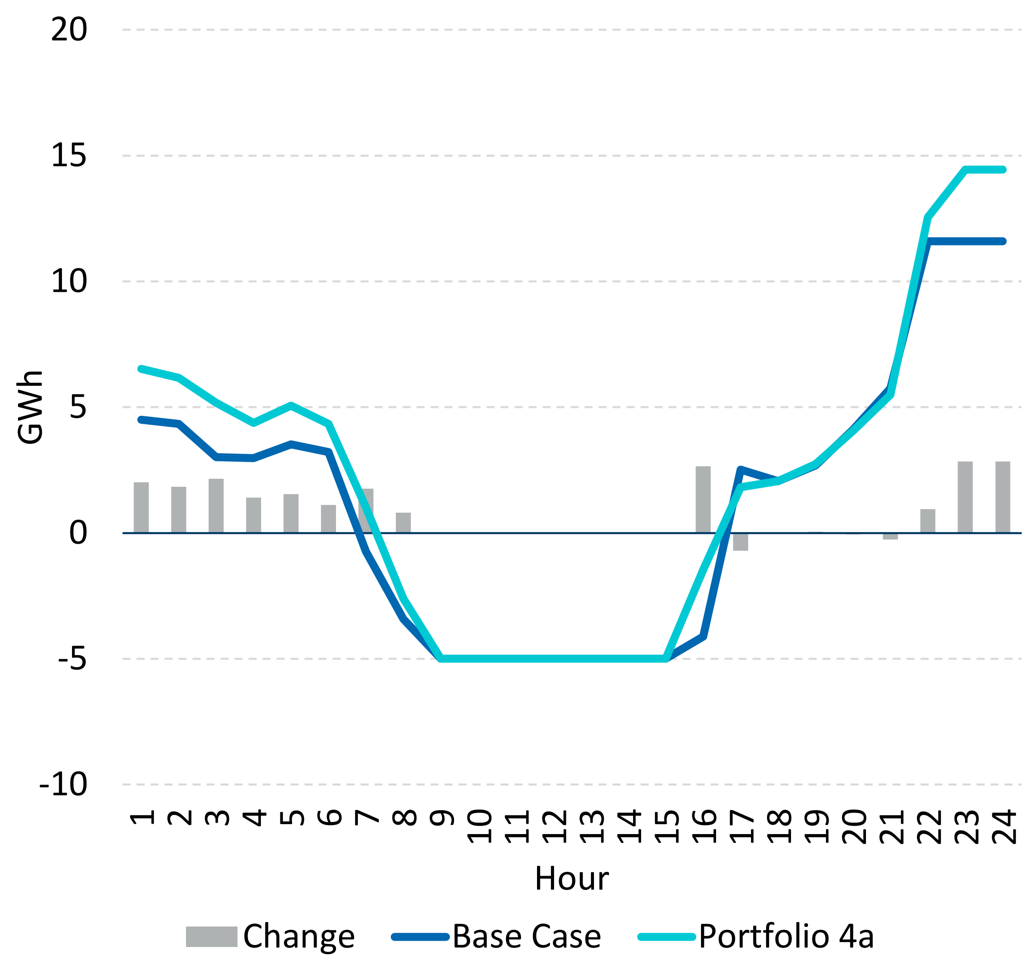
Portfolio 4: Transmission Additions

Modeling Results: Portfolio 4a- Impact of Increasing Interface Limit

Assumptions

Assumption	Base Case	Portfolio 4
Period of interest	3 days (24-hour cycles) in winter, including the peak day	
CAISO Interface with rest of WECC	Maximum import limit of 11,600 MW	Maximum import limit for winter days modeled: 11,600 MW + 2,875 MW = 14,475 MW
Allowed natural gas burn for affected Southern California plants	None	Not to exceed 468 MMCF on a daily basis

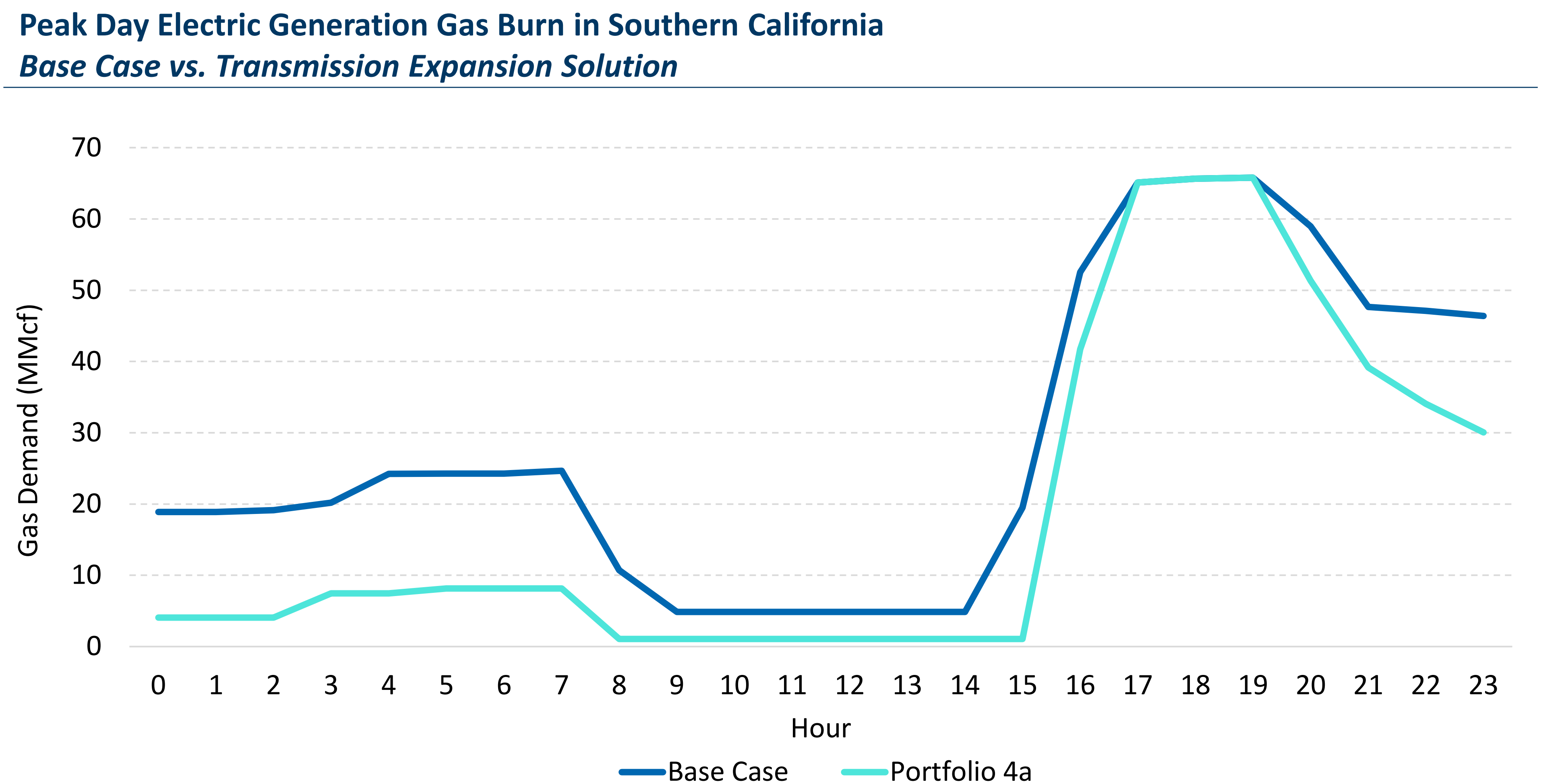
CAISO Interface Portfolio 4a During 2035 Peak Winter Day Base Case vs. Transmission Case



Notes:

- Change in dispatch of units on WECC-wide basis allows gas burn constraint to be met
- Analysis shows that imports are used at higher levels than Base Case during early morning hours and considerably more between 10 pm and midnight, reflecting least cost dispatch subject to gas burn constraint

Modeling Results: Portfolio 4a- Peak Day Electric Generation Gas Burn in Southern California



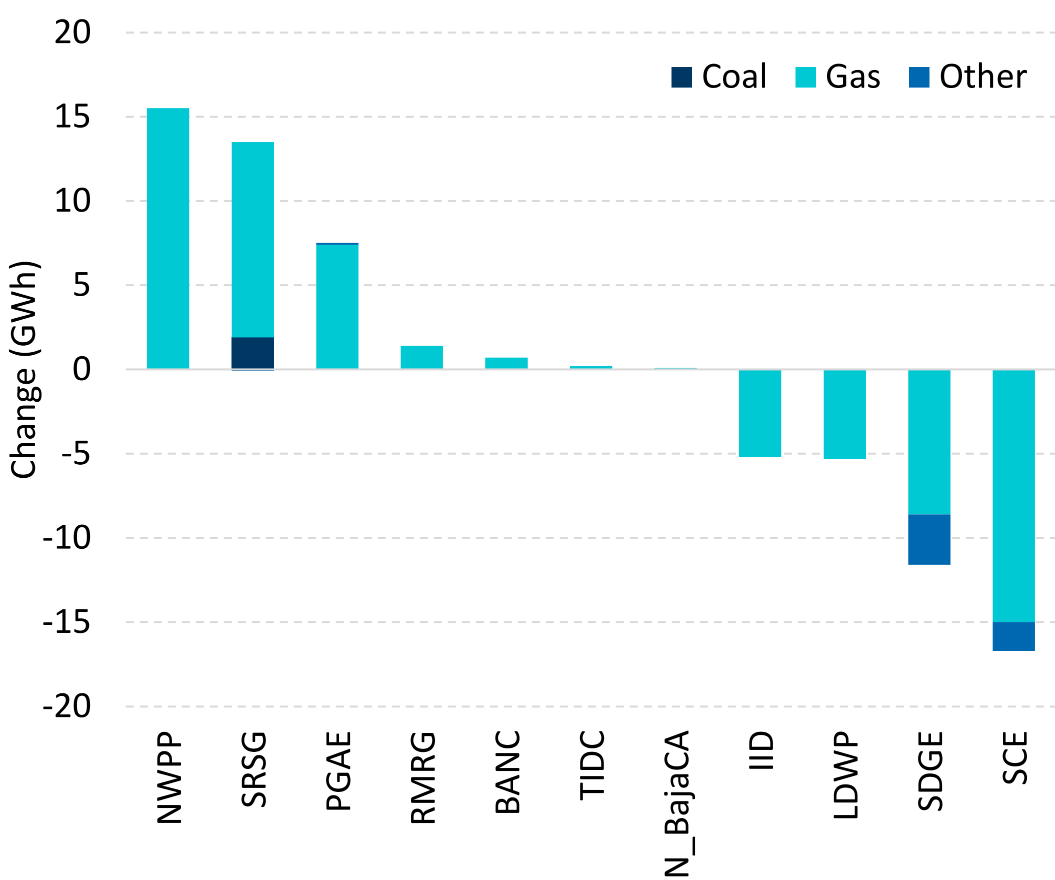
Notes:

- Less gas is burned during 24-hour period
- Higher imports from outside CAISO allows sharp reductions in gas burn between 1 am and 9 am preserving daily gas available for evening ad late evening hours

Portfolio 4: Transmission Additions

Modeling Results: Portfolio 4a – Change in WECC Dispatch with Increase in CAISO Interface Limit

Change in GWh by Region: Portfolio 4a



Abbrev.	Name
SRSG	Southwest Reserve Sharing Group
NWPP	Northwest Power Pool
PGAE	Pacific Gas and Electric Company
N_BajaCA	North Baja California
BANC	Balancing Authority of Northern California
TIDC	Turlock Irrigation District
RMRG	Rocky Mountain Reserve Group
LDWP	Los Angeles Department of Water and Power
IID	Imperial Irrigation District
SDGE	San Diego Gas & Electric
SCE	Southern California Edison

Notes:

- Impact is predominantly displacement of gas use within Southern California with gas use outside Southern California on winter peak day
- Lower gas burn in Southern California results in increased gas burn in the Pacific Northwest and Southwest

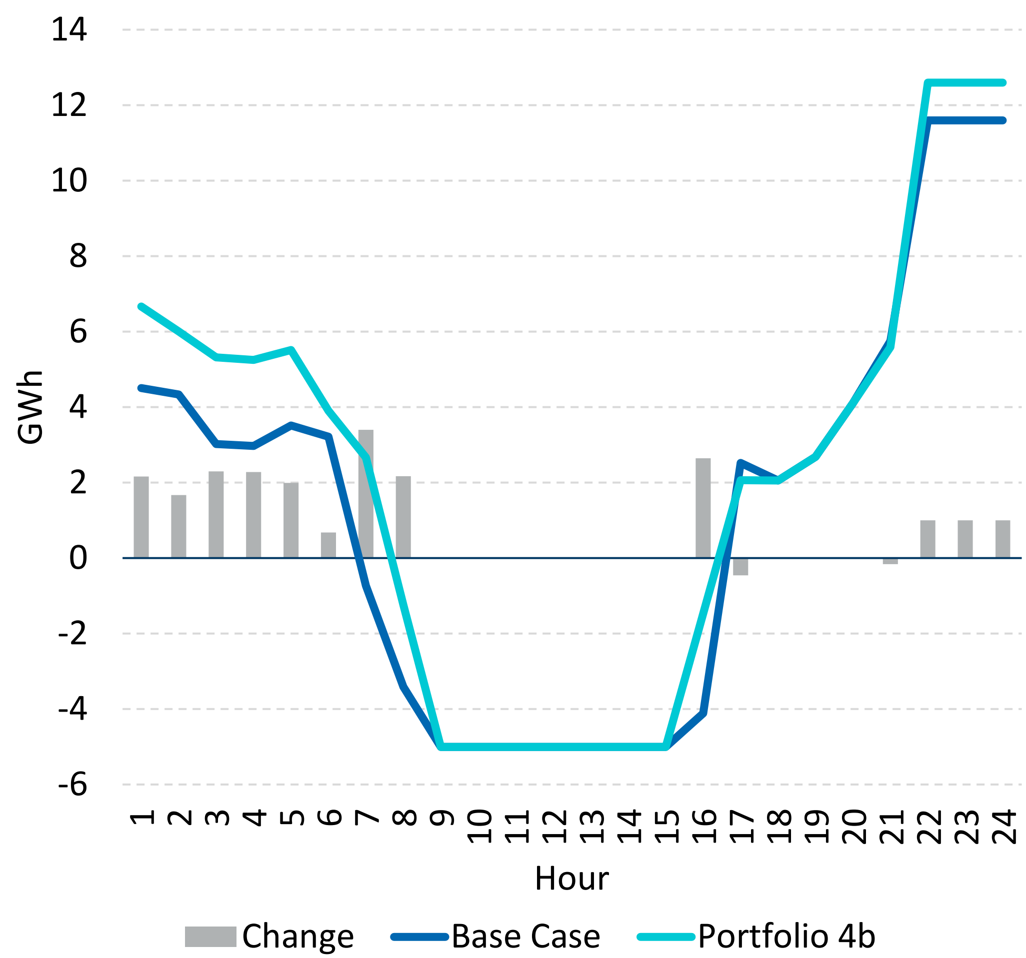
Portfolio 4: Transmission Additions

Modeling Results: Portfolio 4b- Impact of Increasing Interface Limit

Assumptions

Assumption	Base Case	Portfolio 4
Period of interest	3 days (24-hour cycles) in winter, including the peak day	
CAISO Interface with rest of WECC	Maximum import limit of 11,600 MW	Maximum import limit for winter days modeled: 11,600 MW + 1,000 MW = 12,600 MW
Arizona to LADWP (i.e., not into CAISO)	As specified in SERVM	SERVM Level + 1,000 MW Whether this change will affect CAISO interface limit requires power flow modeling
Allowed natural gas burn for affected Southern California plants	None	Not to exceed 468 MMCF on a daily basis

CAISO Interface Portfolio 4b During 2035 Peak Winter Day Base Case vs. Transmission Case

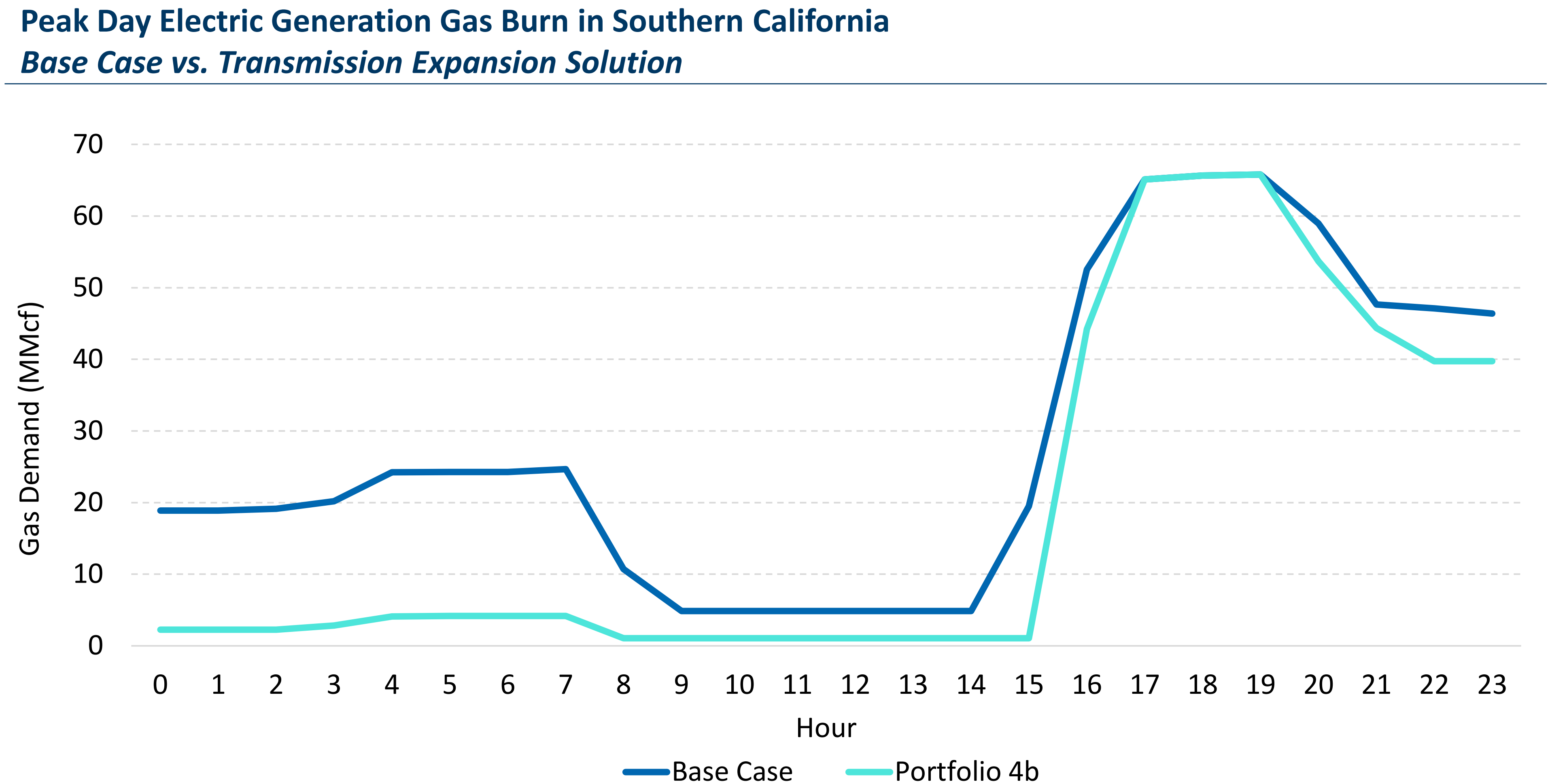


Notes:

- Change in dispatch of units on WECC-wide basis allows gas burn constraint to be met even with sum of transmission changes smaller than Alternative 1
- Pattern of imports into California like Alternative 1

Portfolio 4: Transmission Additions

Modeling Results: Portfolio 4b- Peak Day Electric Generation Gas Burn in Southern California



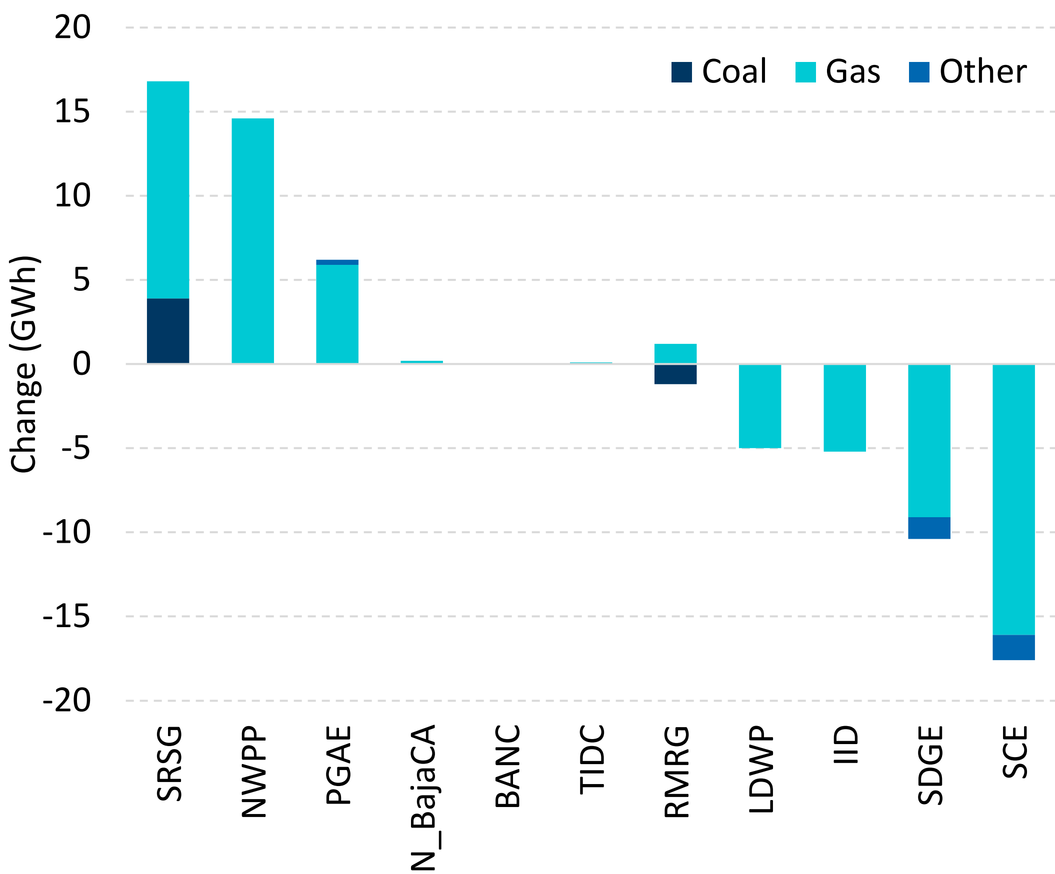
Notes:

- Pattern is similar to Portfolio 4a
- Decrease in gas burn in the 1 am to 9 am period more pronounced

Portfolio 4: Transmission Additions

Modeling Results: Portfolio 4b – Change in WECC Dispatch with Increase in CAISO Interface Limit

Change in GWh by Region: Solution 4b



Abbrev.	Name.
SRSG	Southwest Reserve Sharing Group
NWPP	Northwest Power Pool
PGAE	Pacific Gas and Electric Company
N_BajaCA	North Baja California
BANC	Balancing Authority of Northern California
TIDC	Turlock Irrigation District
RMRG	Rocky Mountain Reserve Group
LDWP	Los Angeles Department of Water and Power
IID	Imperial Irrigation District
SDGE	San Diego Gas & Electric
SCE	Southern California Edison

Notes:

- Impact is predominantly displacement of gas use within Southern California with gas use outside Southern California on winter peak day
- Lower gas burn in Southern California results in increased gas burn in the Pacific Northwest, Southwest, and PG&E

Portfolio 4: Transmission Additions

Cost-Benefit Analysis: Portfolio 4a

Cost-Benefit Analysis (2019$'s in 2027)

	2027	2035
Cost	**N/A**	**$111,221,000**
Levelized Annual Cost	N/A	$111,221,000
Benefits	**N/A**	**$168,085,000**
Gas Cost Reduction	N/A	$2,349,000
Electricity Cost Reduction	N/A	$105,746,000
Resource Adequacy Increase	N/A	$57,241,000
CA CO2 Emissions Reduction*	N/A	$2,749,000
Net Benefit	**N/A**	**$56,864,000**
Benefit Cost Ratio	**N/A**	**1.51**

Cost-Benefit Discussion

- This portfolio's annual costs are the third highest across all portfolios.
- The second highest Benefit-Cost ratios, but this does not factor siting/permitting issues and being only a long-term solution
- 6.4% capital recovery factor from the National Renewable Energy Laboratory 2021 Annual Technology Baseline.
- Electricity cost reduction (wholesale cost to load) is from PLEXOS
- Gas cost reduction cost is from GPCM
- Resource adequacy benefit is based on CPUC-reported RA prices
- CO2 emissions
  - Includes CA and transmission imports
  - Uses Social Cost of Carbon of $51/tonne

Portfolio 4: Transmission Additions

Cost-Benefit Analysis: Portfolio 4b

Cost-Benefit Analysis (2019$'s in 2027)

	2027	2035
Cost	**N/A**	**$79,627,000**
Levelized Annual Cost	N/A	$78,077,000
CA CO2 Emissions Increase	N/A	$1,545,000
Benefits	**N/A**	**$147,482,000**
Gas Cost Reduction	N/A	$2,642,000
Electricity Cost Reduction	N/A	$104,657,000
Resource Adequacy Increase	N/A	$40,183,000
Net Benefit	**N/A**	**$67,855,000**
Benefit Cost Ratio	**N/A**	**1.85**

Cost-Benefit Discussion

- This portfolio's annual cost is the second lowest across all portfolios.
- The highest Benefit-Cost ratio, but this does not factor siting/permitting issues and being only a long-term solution
- 6.4% capital recovery factor from the National Renewable Energy Laboratory 2021 Annual Technology Baseline.
- Electricity cost reduction (wholesale cost to load) is from PLEXOS
- Gas cost reduction cost is from GPCM
- Resource adequacy benefit is based on CPUC-reported RA prices
- CO2 emissions
  - Includes CA and transmission imports
  - Uses Social Cost of Carbon of $51/tonne

Portfolio 5:
Gas Demand Reduction and Complementary Solutions

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Portfolio 5: Gas Demand Reduction and Complementary Solutions

Overview: Design of Hybrid Solution

Key Takeaways from Portfolios 1-4	
	- Portfolios 1a and 1b can each cover the entire shortfall, but they entail capital investments, require siting/permitting, and offer no GHG reduction. - Industrial Demand Response, a component of Portfolio 2, offers multiple benefits – relatively low cost, no siting/permitting, and could potentially address the entire shortfall by 2027. However, the volumes available must be discovered through a reverse auction. - Portfolio 3 will require significant capital investments along with siting/permitting to cover the entire shortfall; however, it offers wholesale price and resource adequacy benefits along with GHG reductions. - Portfolios 4a and 4b are only applicable for the 2035 target date, require significant sting/permitting, and capital investments to cover the entire shortfall. However, they offer wholesale price and resource adequacy benefits.

Hybrid Solution

Portfolio 5 combines the most attractive features from Portfolios 1 through 4 and will be assessed with target dates of 2027 and 2035.

Portfolio 5: Gas Demand Reduction and Complementary Solutions

Path to 2027 Shutdown

Electric generation is the complementary solution under this portfolio; up to three sensitivities will be assessed on different penetration levels of electrification, energy efficiency, and demand response.

Key Activities

2022

- Test the market for how much Non-Core demand response is reliably available by conducting a reverse auction
- Determine how much electric energy efficiency and building electrification penetration must be accomplished
- Approve detailed plans for procuring new electric generation that is needed to fill possible gap

2023-2026

- Monitor progress on detailed plan for 2027 shutdown based on:
  - Non-Core demand response (firm estimate available)
  - Expected building electrification and energy efficiency penetration levels
  - Progress on electric generation procurement
- Update modeling, analysis, and plan, as necessary

2027: Shutdown

- Confirm all pieces are on track
- Proceed with shutdown

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Portfolio 5: Gas Demand Reduction and Complementary Solutions

Path to 2035 Shutdown

Transmission expansion is the complementary solution under this portfolio to fill the shortfall gap; three similar portfolio sensitivities also will be assessed.

Key Activities

2022

- Test the market for how much Non-Core demand response is reliably available by conducting a reverse auction
- Determine how much electric energy efficiency and building electrification penetration must be accomplished
- Monitor changing plans on generator additions/retirements
- Approve detailed plans for procuring new transmission that is needed to fill possible gap

2023-2034

- Monitor progress on detailed plan for 2035 shutdown based on:
  - Non-Core demand response (firm estimate available)
  - Expected building electrification and energy efficiency penetration levels
  - Changing plans on generator additions/ retirements
  - Changing plans on transmission projects and revisions to interface limits
- Update modeling, analysis, and plan, as necessary

2035: Shutdown

- Confirm all pieces are on track
- Proceed with shutdown

Appendix: Detailed Hydraulic Model Results

Portfolio 1a- 2027 and 2035 Northern Zone Supply Expansions

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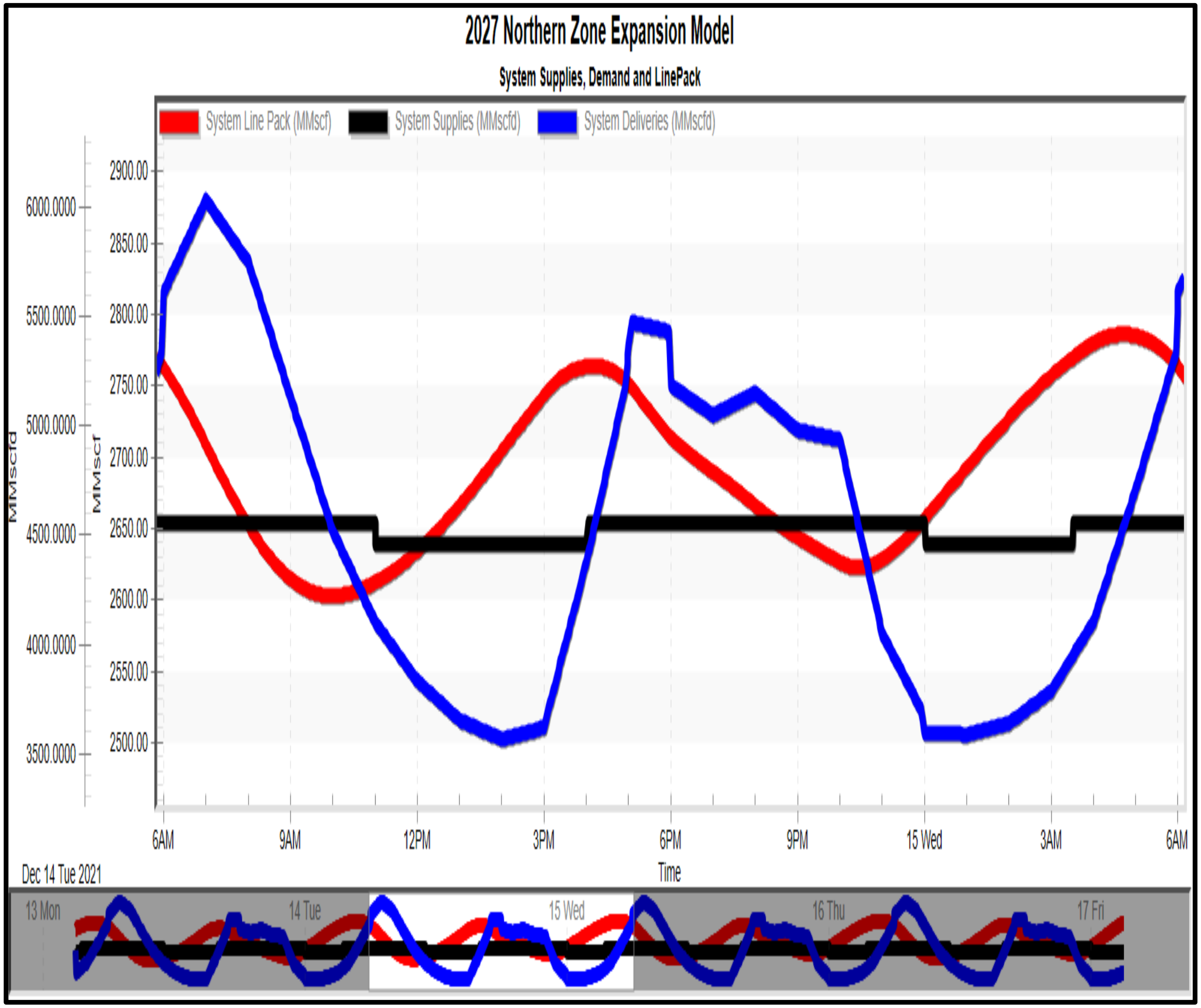
Portfolio 1: Gas Transmission System Expansion

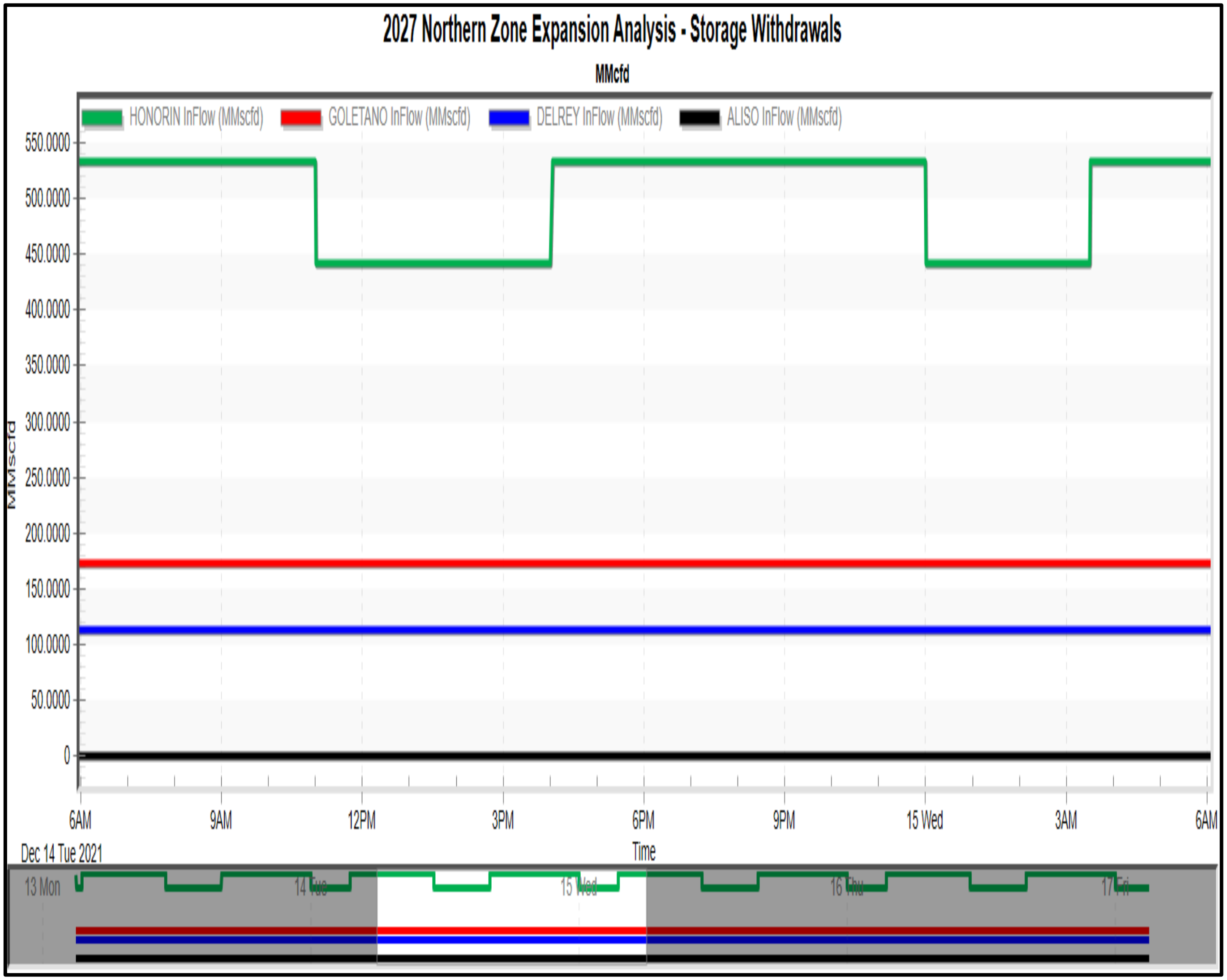
Portfolio 1a - 2027 Northern Zone Supply/Expansions – Hydraulic Model Line Pack



- Line Pack fully recovers from 2,762 MMcf at 6AM start to 2,762 MMcf at 6AM twenty-four hours later.
- Hourly Delivery Swings range from low of 3,566 MMcf/d at 2:00 PM to high of 6,035 MMcf/d at 7:00 AM.
- Supply Changes supported by line pack and withdrawal quantity adjustments made during the day at Honor Rancho.

Portfolio 1: Gas Transmission System Expansion

Portfolio 1a- 2027 Northern Zone Supply/Expansions – Hydraulic Model Storage Use

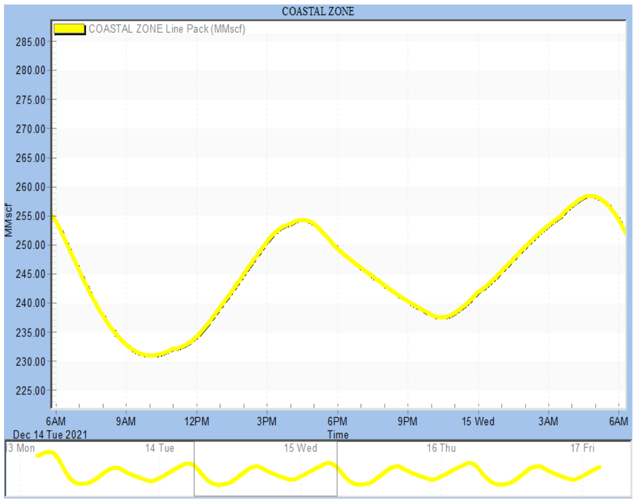


- Honor Rancho Withdrawals at Maximum rate of 534 MMcf/d from 3:30 AM to 11:00 AM and 4:00 PM to 12:00 AM.
- Honor Rancho Withdrawals minimized from 11:00 AM to 4:00 PM and 12:00 AM to 3:30 AM at rate of 442 MMcf/d
- La Goleta and Playa Del Rey withdrawals at constant levels of 173 MMcf/d and 114 MMcf/d respectively.
- Aliso Canyon assumed out of service with no withdrawals.

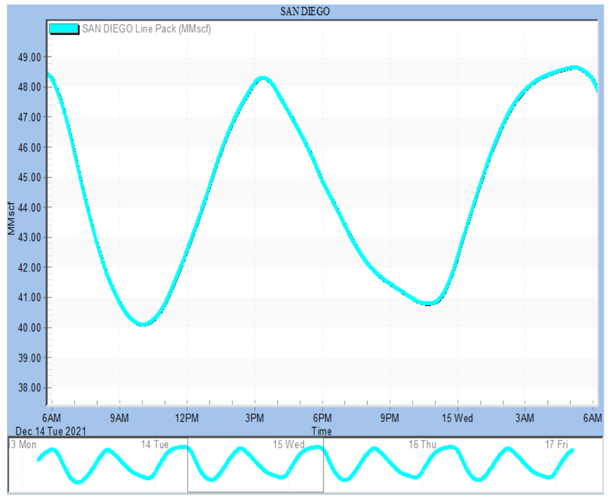
Portfolio 1: Gas Transmission System Expansion

Portfolio 1a - 2027 Northern Zone Supply/Expansions – Subsystems Line Pack

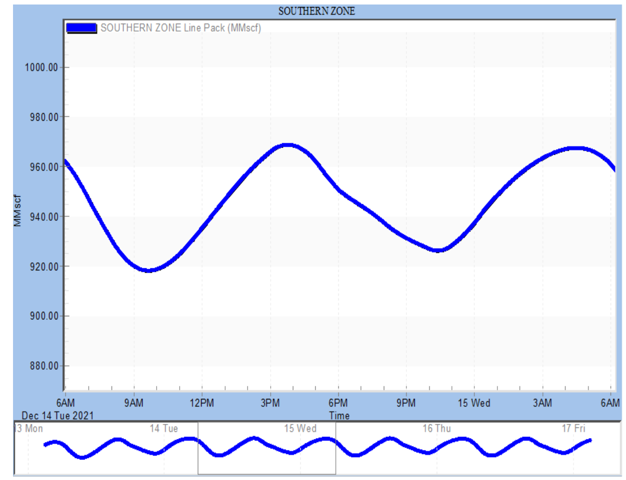
Coastal Zone



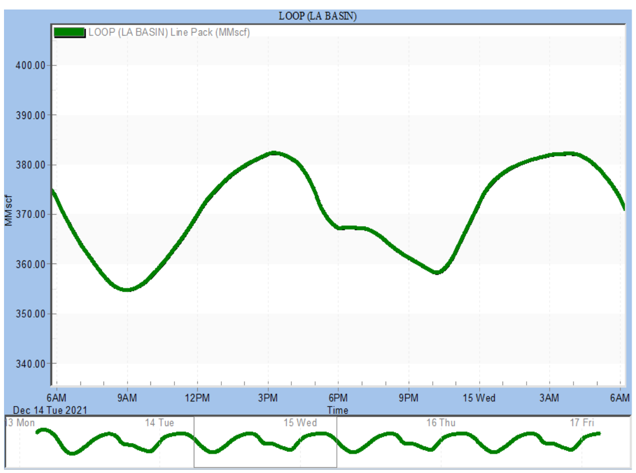
San Diego Zone



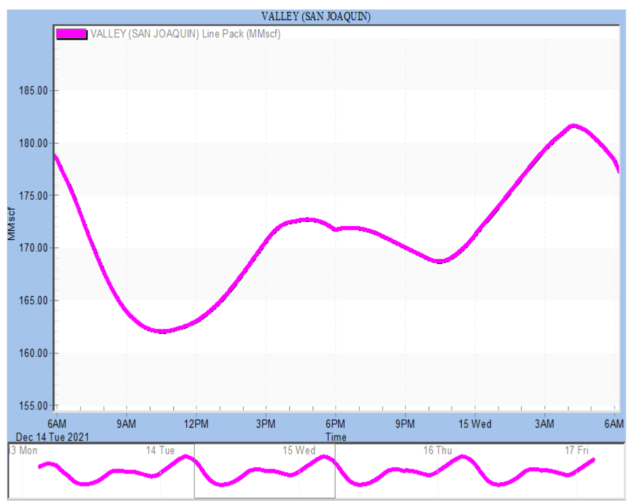
Southern Zone



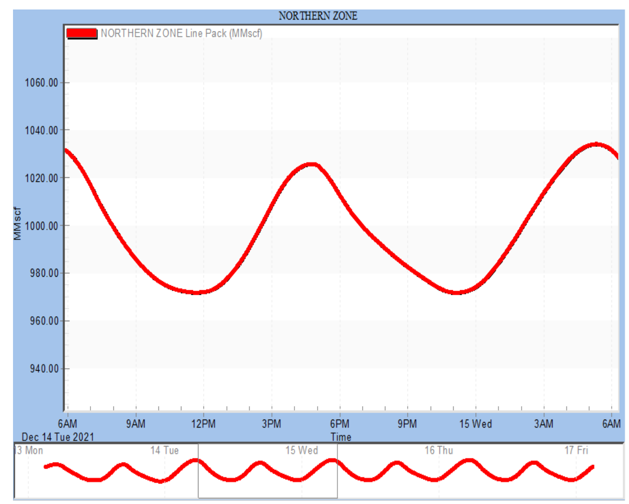
Loop (LA Basin) Zone



Valley (San Joaquin) Zone

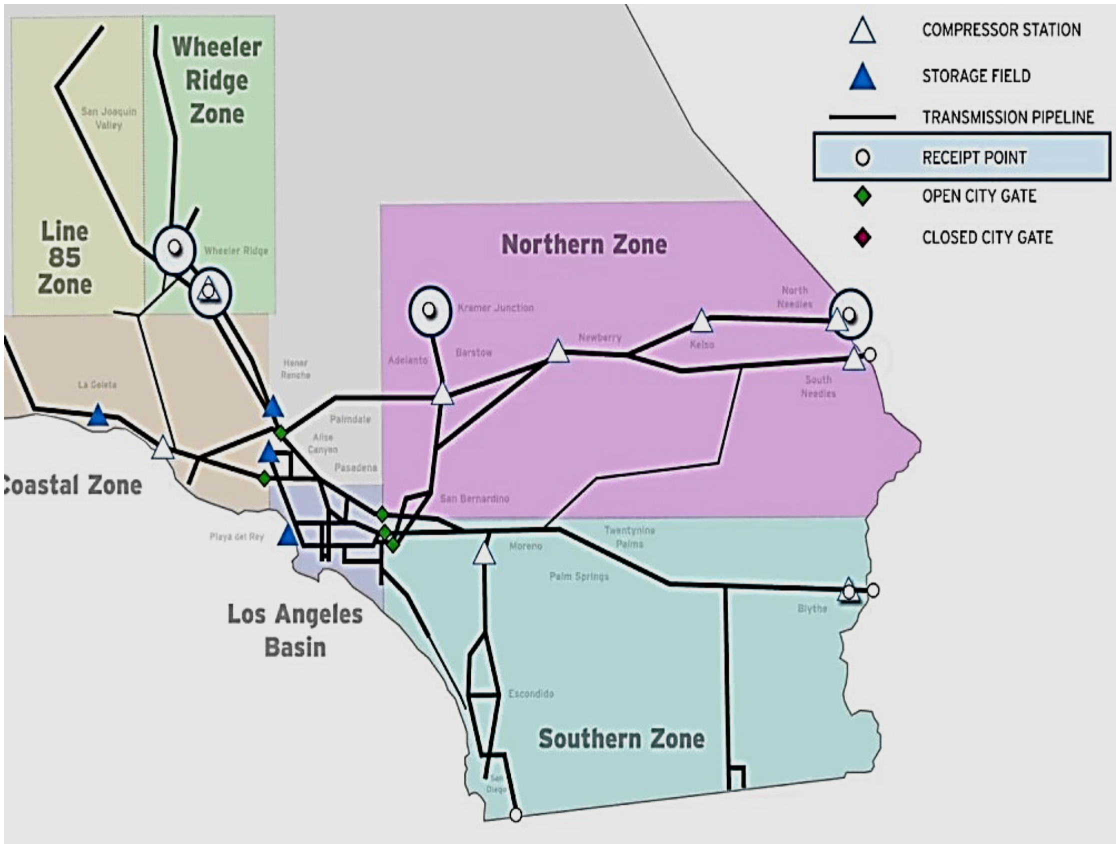


Northern Zone



Portfolio 1: Gas Transmission System Expansion

Portfolio 1a - 2027 Northern Zone Supply/Expansions – Subsystems Line Pack

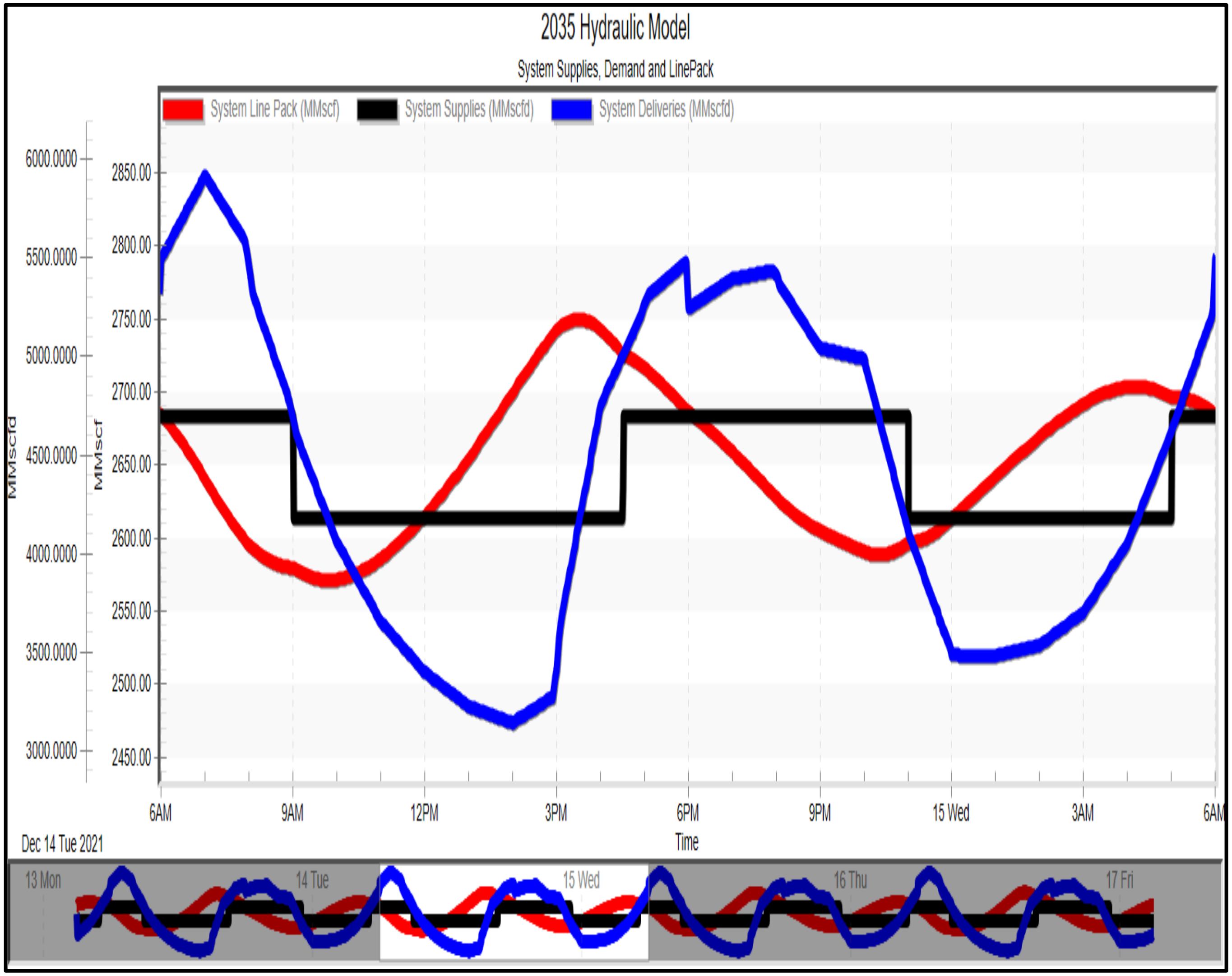


- **Line Pack recovers for ALL Zones in 2027 1-in-10 Demand Day Model with Adjusted Demand**

Zone	Day 1 – Midnight LinePack (MMscf)	Day 2 – Midnight LinePack (MMscf)
Coastal Zone	**240.2**	**241.9**
San Diego Zone	**42.1**	**42.4**
LA Basin Zone	**370.2**	**372.4**
Valley Zone	**170.3**	**171.2**
Northern Zone	**970.3**	**974.2**
Southern Zone	**935.3**	**937.4**

Portfolio 1: Gas Transmission System Expansion

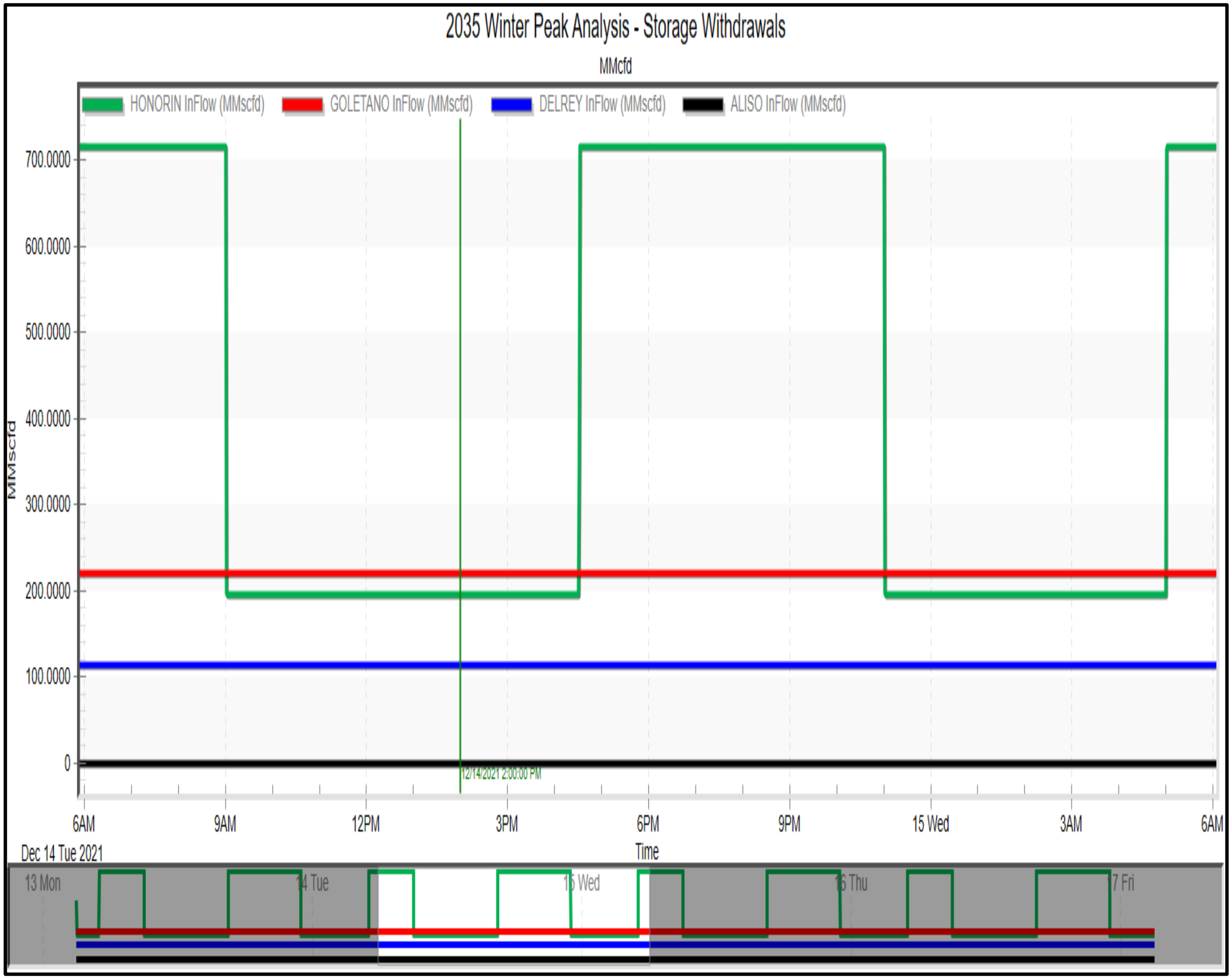
Portfolio 1a – 2035 Northern Zone Supply/Expansions – Hydraulic Model Line Pack



- Line Pack fully recovers from 2,685 MMcf at 6:00 AM start to 2,685 MMcf at 6AM twenty-four hours later.
- Hourly Delivery Swings range from low of 3,140 MMcf/d at 2:00 PM to high of 5,918 MMcf/d at 7:00 AM.
- Supply Changes supported by line pack and withdrawal quantity adjustments made during the day at Honor Rancho.

Portfolio 1: Gas Transmission System Expansion

Portfolio 1a - 2035 Northern Zone Supply/Expansions – Hydraulic Model Storage Use

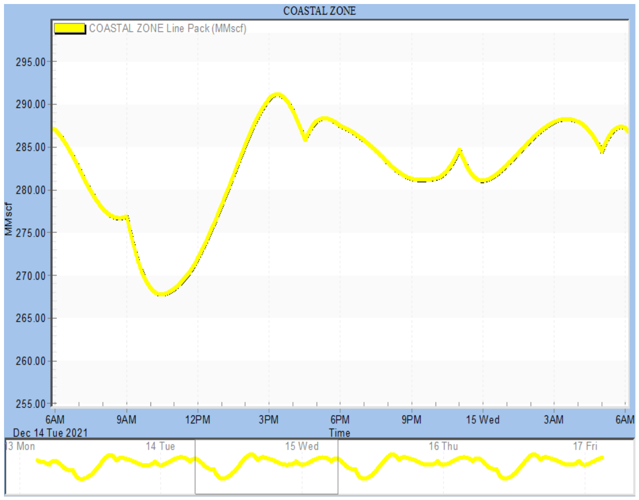


- Honor Rancho Withdrawals at Maximum rate of 715 MMcf/d from 5:00 AM to 9:00 AM and 4:30 PM to 11:00 PM.
- Honor Rancho Withdrawals minimized from 9:00 AM to 4:30 PM and 11:00 AM to 5:00 AM at rate of 195 MMcf/d
- La Goleta and Playa Del Rey withdrawals at constant levels of 221 MMcf/d and 114 MMcf/d respectively.
- Aliso Canyon assumed out of service with no withdrawals.

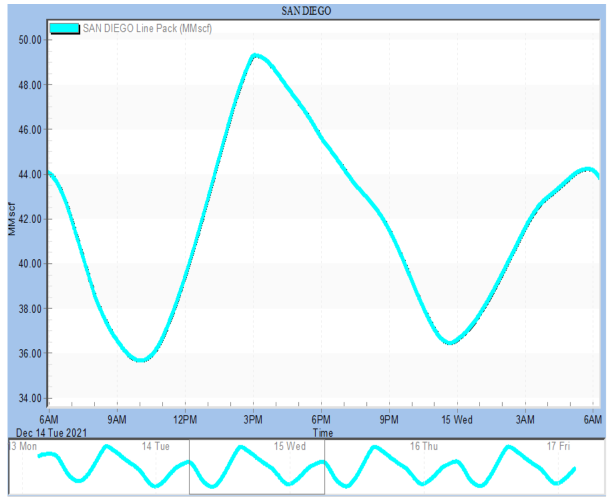
Portfolio 1: Gas Transmission System Expansion

Portfolio 1a - 2035 Northern Zone Supply/Expansions – Subsystems Line Pack

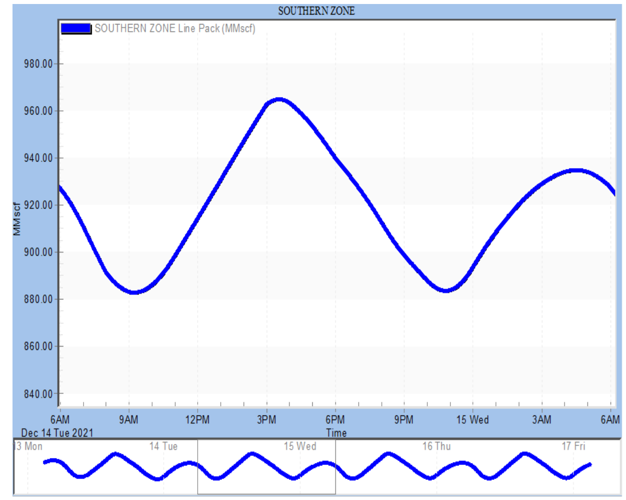
Coastal Zone



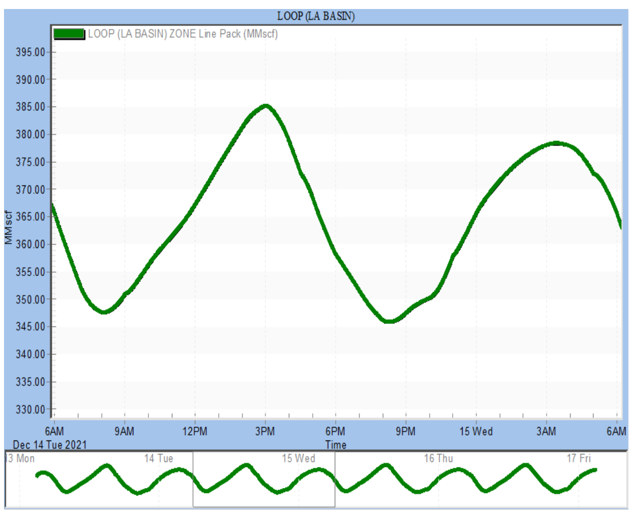
San Diego Zone



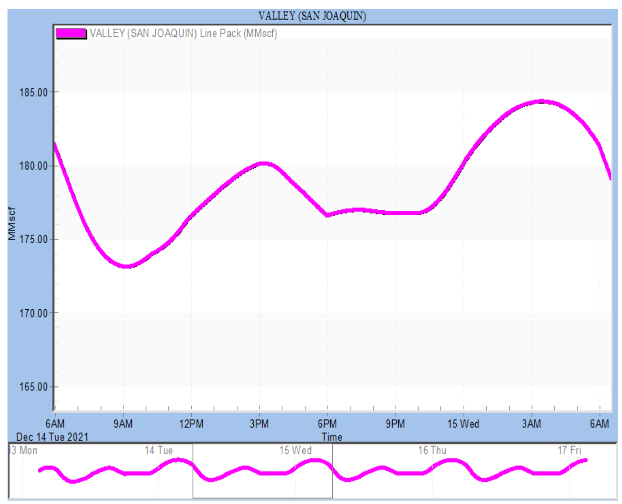
Southern Zone



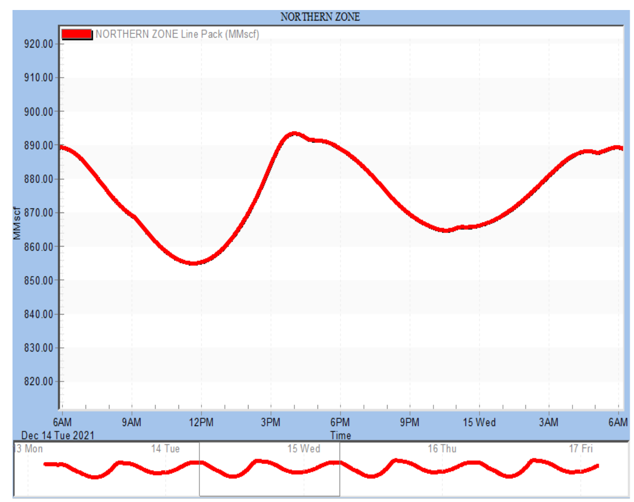
Loop (LA Basin) Zone



Valley (San Joaquin) Zone

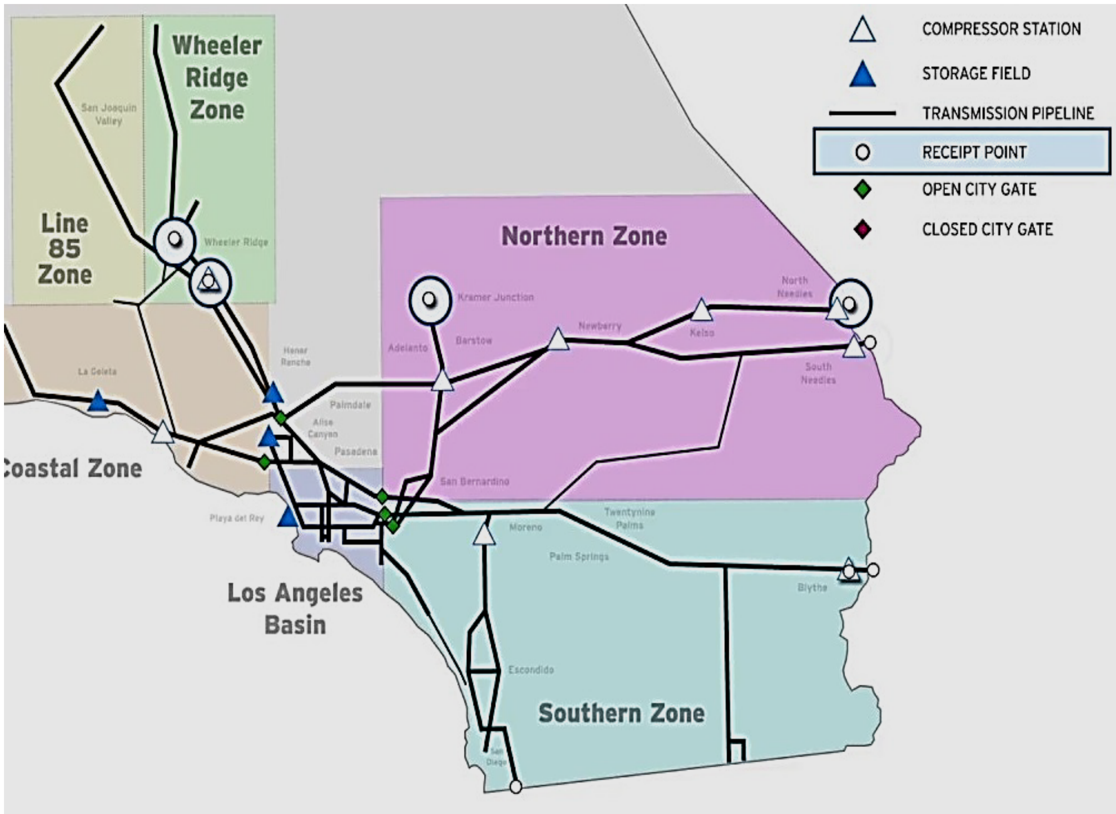


Northern Zone



Portfolio 1: Gas Transmission System Expansion

Portfolio 1a - 2035 Northern Zone Supply/Expansions – Subsystems Line Pack



- **Line Pack recovers for ALL Zones in 2027 1-in-10 Demand Day Model with Adjusted Demand**

Zone	Day 1 – Midnight LinePack (MMscf)	Day 2 – Midnight LinePack (MMscf)
Coastal Zone	**281.1**	**281.1**
San Diego Zone	**36.6**	**36.7**
LA Basin Zone	**365.7**	**365.7**
Valley Zone	**180.1**	**180.1**
Northern Zone	**866.3**	**866.4**
Southern Zone	**893.9**	**894.3**

Appendix: Detailed Hydraulic Model Results

Portfolio 1b - 2027 and 2035 - Wheeler Ridge Supply Expansions

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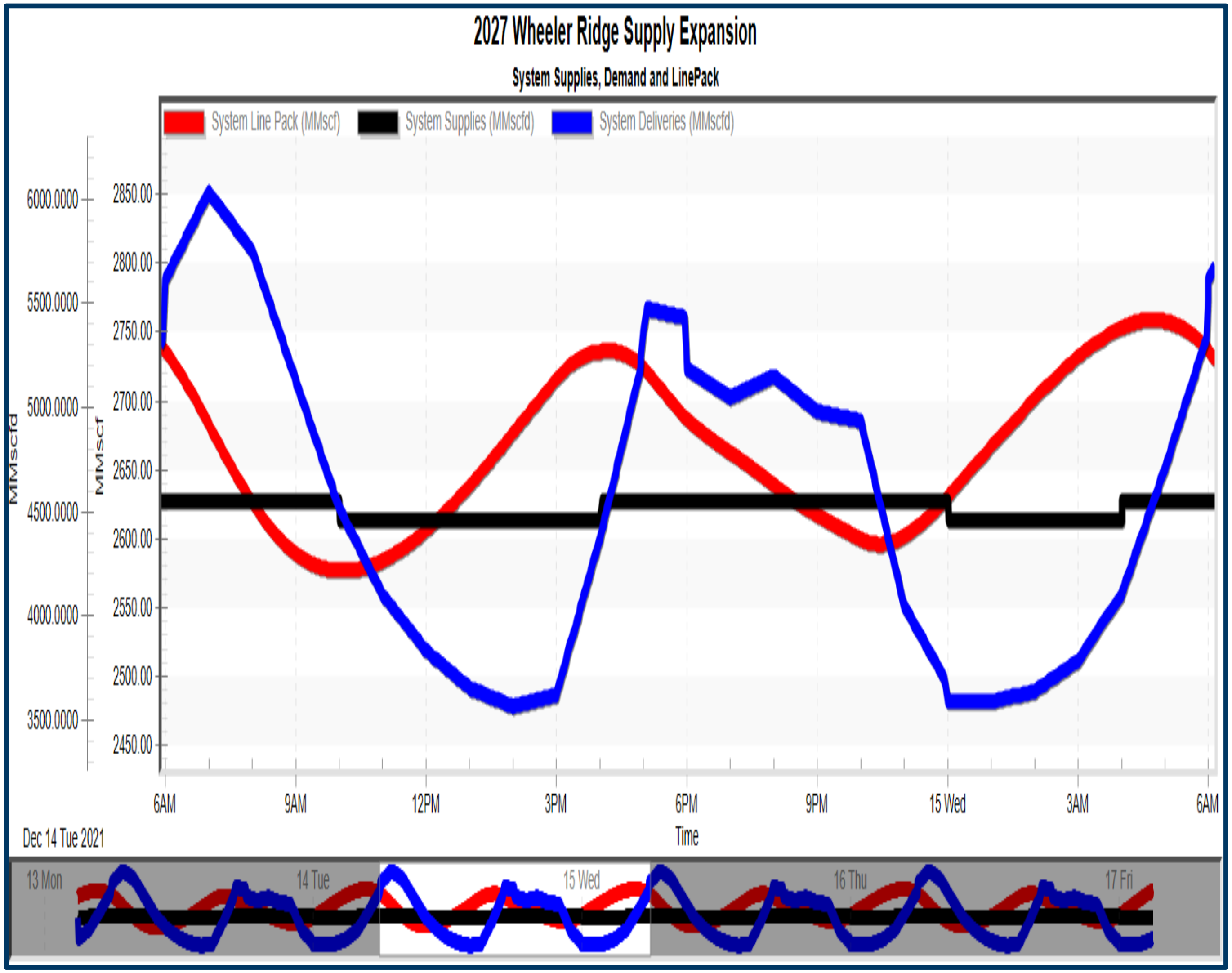
Portfolio 1: Gas Transmission System Expansion

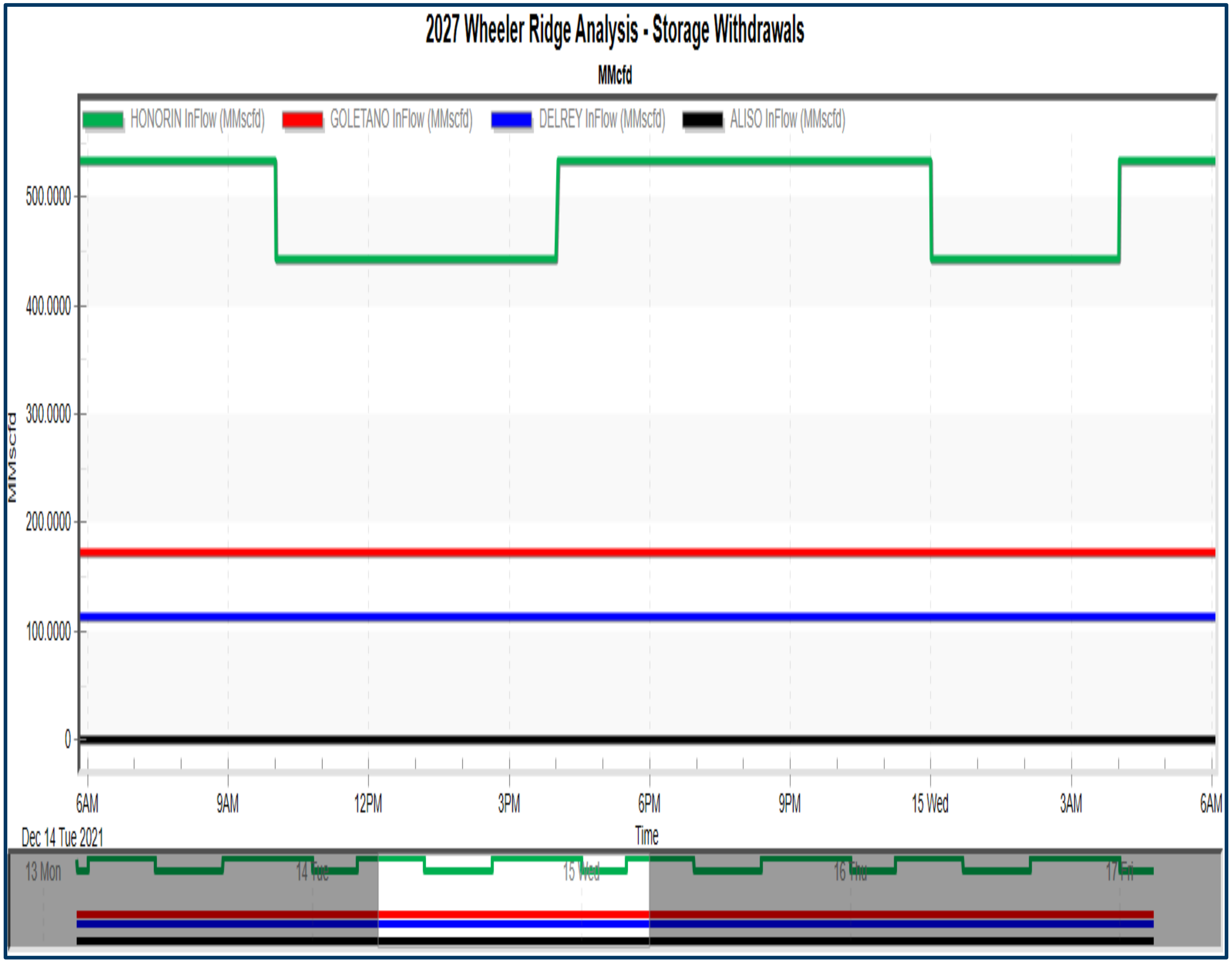
Portfolio 1b– 2027 - Wheeler Ridge Supply/Expansions – Hydraulic Model Line Pack



- Line Pack fully recovers from 2,737 MMcf at 6AM start to 2,737 MMcf at 6AM twenty-four hours later.
- Hourly Delivery Swings range from low of 3,678 MMcf/d at 2:00 PM to high of 6,035 MMcf/d at 7:00 AM.
- Supply Changes supported by line pack and withdrawal quantity adjustments made during the day at Honor Rancho.

Portfolio 1: Gas Transmission System Expansion

Portfolio 1b – 2027 - Wheeler Ridge Supply/Expansions – Hydraulic Model Storage Use

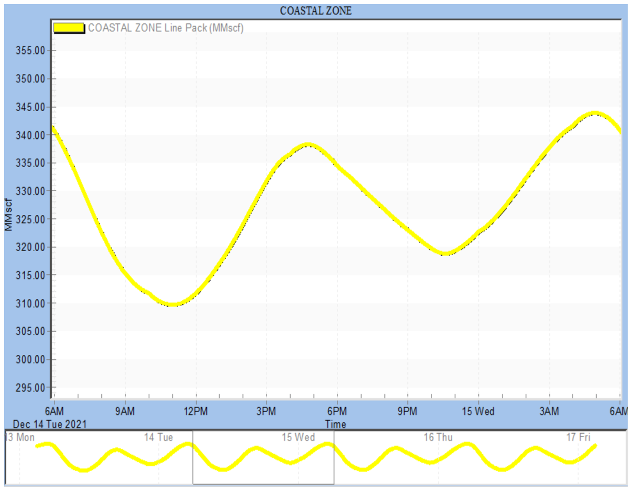


- Honor Rancho Withdrawals at Maximum rate of 534 MMcf/d from 4:00 AM to 10:00 AM and 4:00 PM to 12:00 AM.
- Honor Rancho Withdrawals minimized from 10:00 AM to 4:00 PM and 12:00 AM to 4:00 AM at rate of 443 MMcf/d
- La Goleta and Playa Del Rey withdrawals at constant levels of 173 MMcf/d and 114 MMcf/d respectively.
- Aliso Canyon assumed out of service with no withdrawals.

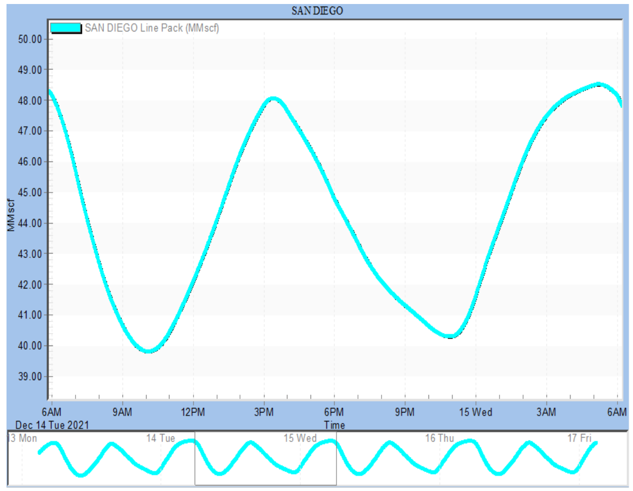
Portfolio 1: Gas Transmission System Expansion

Portfolio 1b - 2027 - Wheeler Ridge Supply/Expansions – Subsystems Line Pack

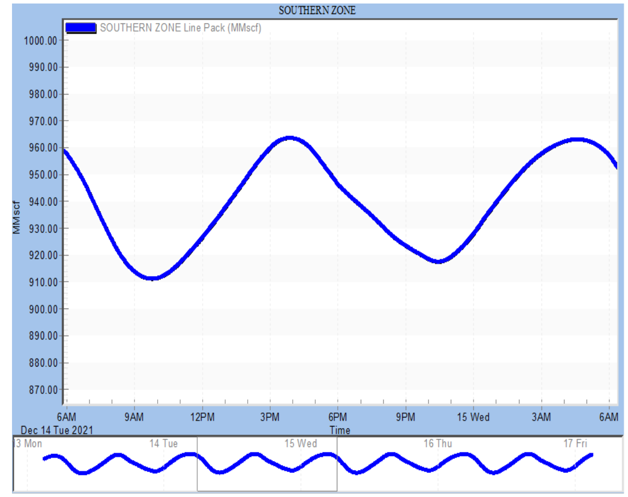
Coastal Zone



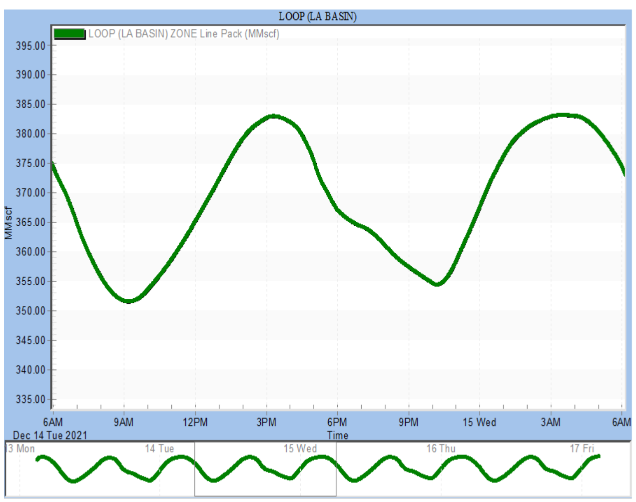
San Diego Zone



Southern Zone

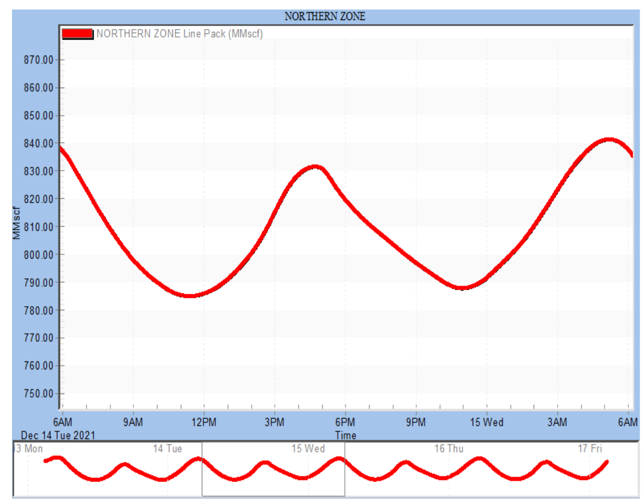


Loop (LA Basin) Zone



Valley (San Joaquin) Zone

Northern Zone



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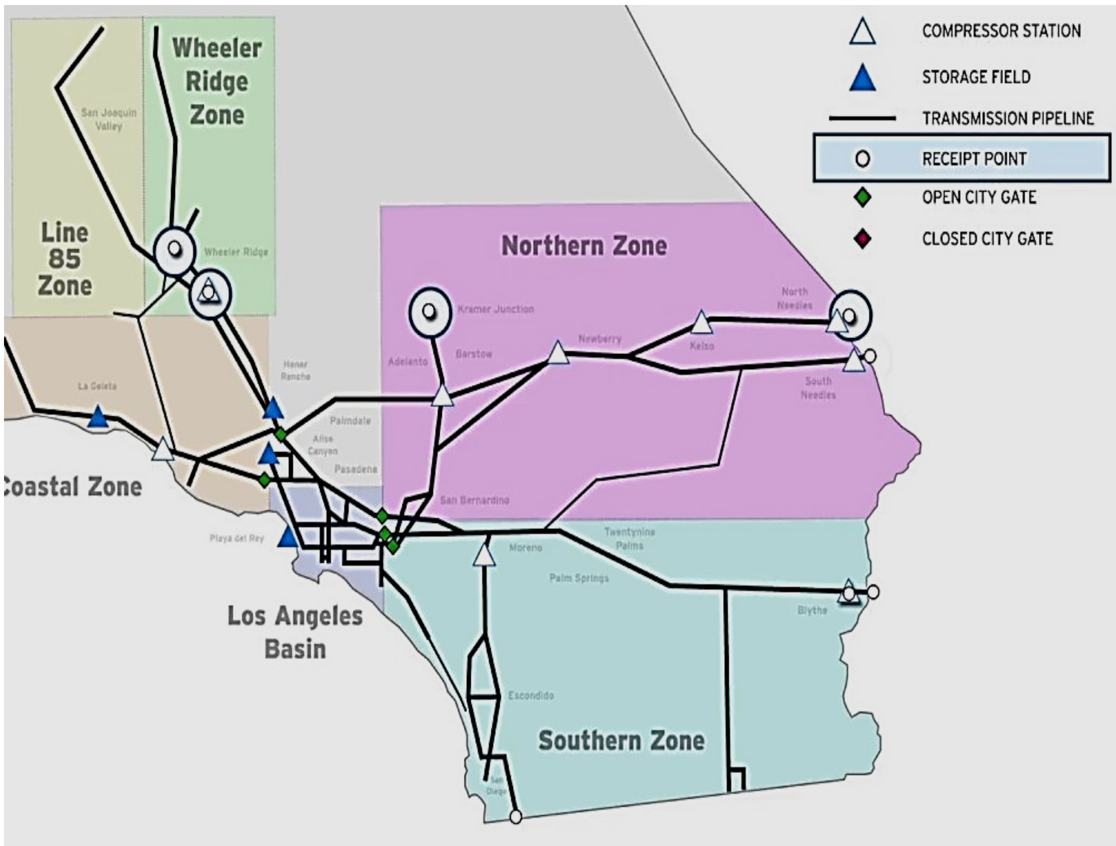
Portfolio 1: Gas Transmission System Expansion

Portfolio 1b - 2027 - Wheeler Ridge Supply/Expansions – Subsystems Line Pack

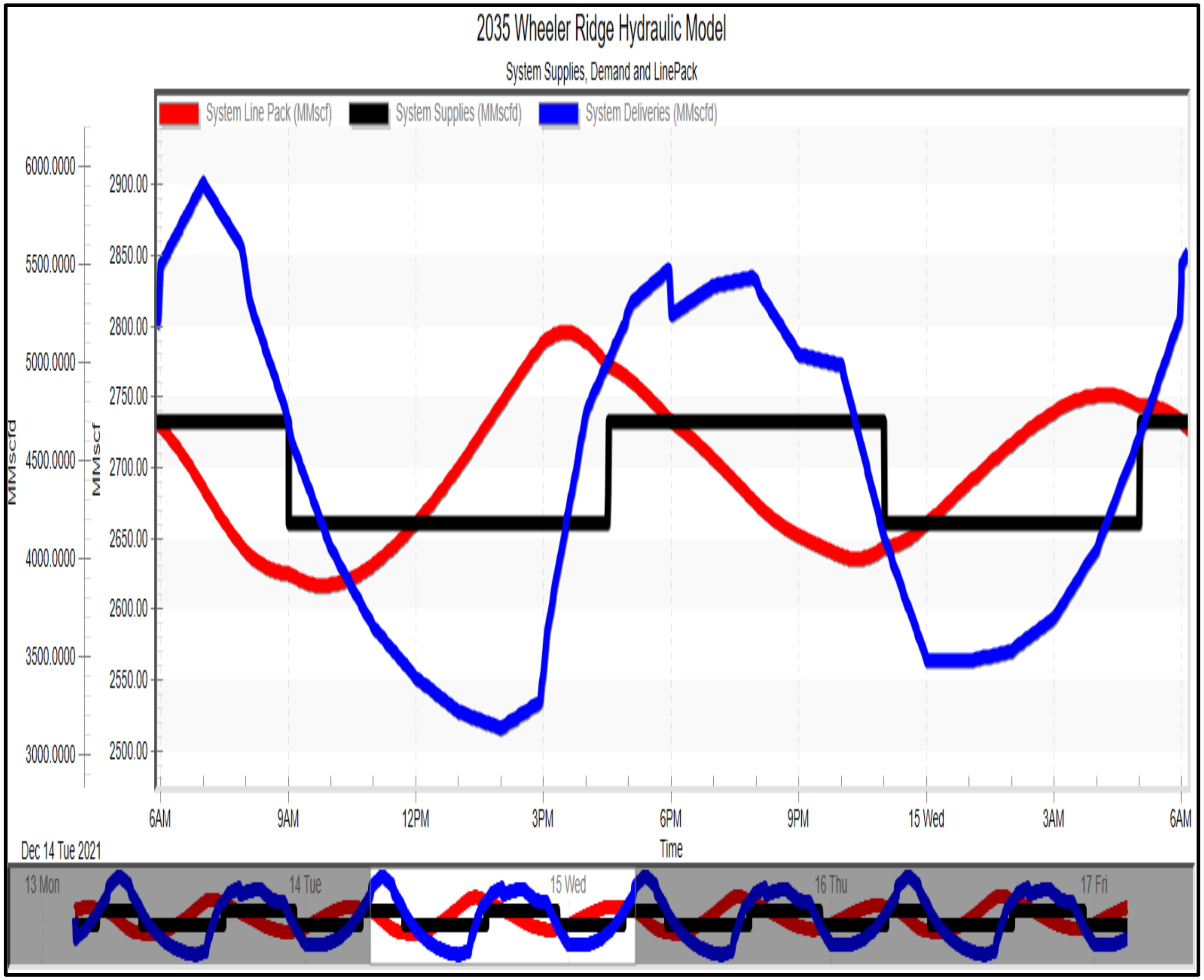


- **Line Pack recovers for ALL Zones in 2027 1-in-10 Demand Day Model with Adjusted Demand**

Zone	Day 1 – Midnight LinePack (MMscf)	Day 2 – Midnight LinePack (MMscf)
Coastal Zone	**320.7**	**322.7**
San Diego Zone	**41.4**	**41.7**
LA Basin Zone	**365.3**	**367.7**
Valley Zone	**178.4**	**178.3**
Northern Zone	**787.6**	**791.7**
Southern Zone	**925.5**	**928.0**

Portfolio 1: Gas Transmission System Expansion

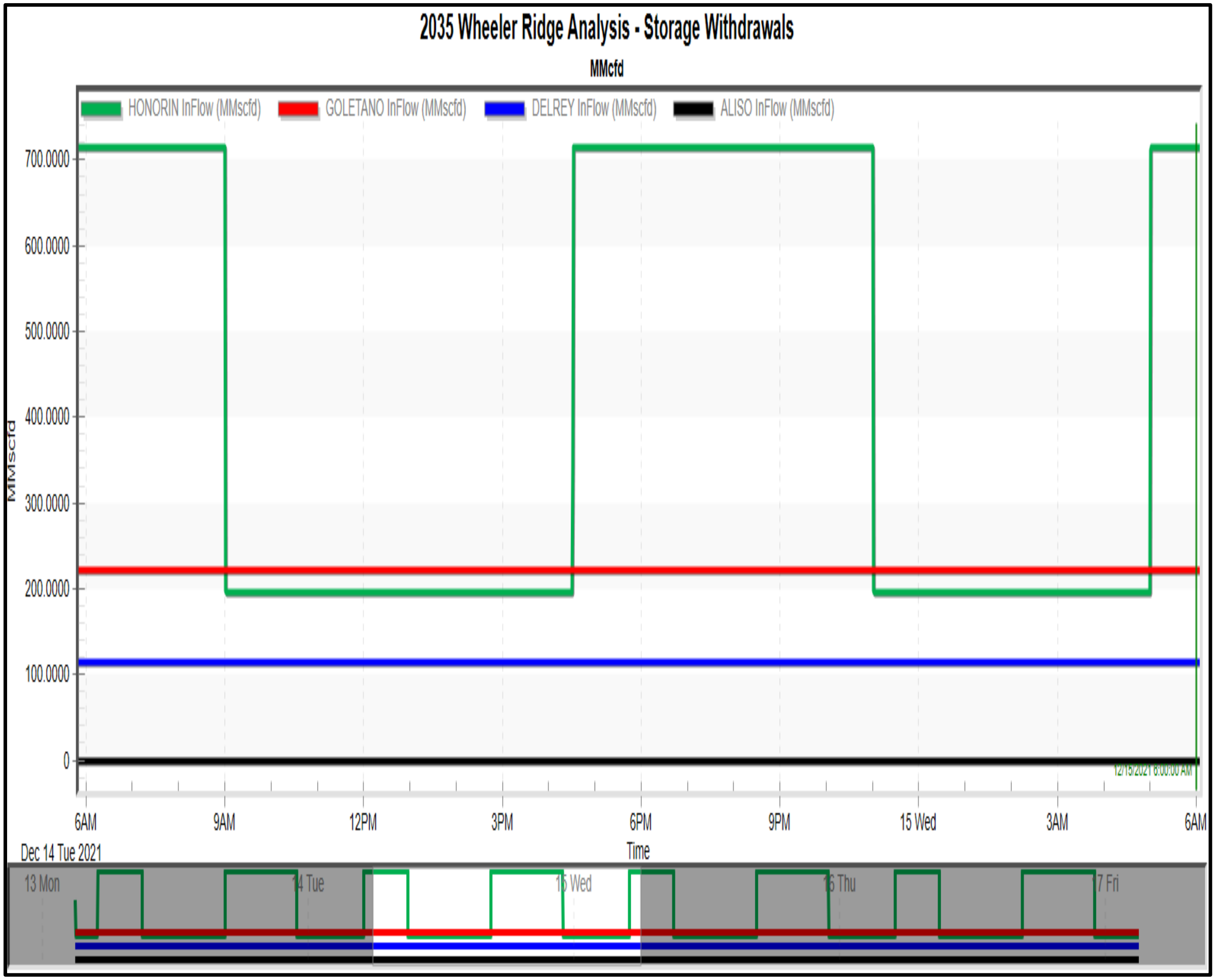
Portfolio 1b – 2035 - Wheeler Ridge Supply/Expansions – Hydraulic Model Line Pack



- Line Pack fully recovers from 2,732 MMcf at 6:00 AM start to 2,732 MMcf at 6AM twenty-four hours later.
- Hourly Delivery Swings range from low of 3,140 MMcf/d at 2:00 PM to high of 5,918 MMcf/d at 7:00 AM.
- Supply Changes supported by line pack and withdrawal quantity adjustments made during the day at Honor Rancho.

Portfolio 1: Gas Transmission System Expansion

Portfolio 1b – 2035 - Wheeler Ridge Supply/Expansions – Hydraulic Model Storage Use

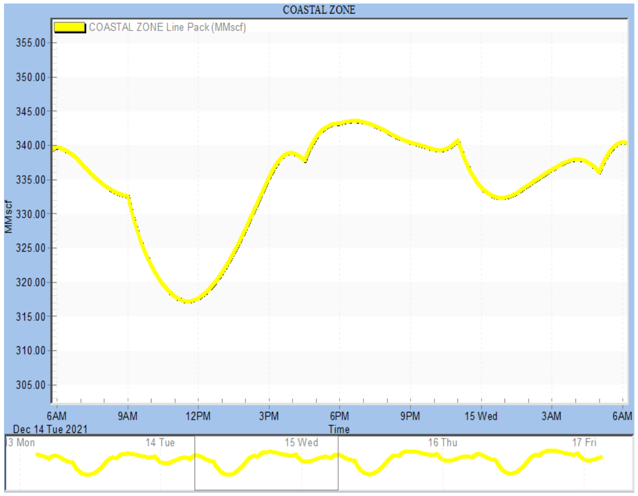


- Honor Rancho Withdrawals at Maximum rate of 715 MMcf/d from 5:00 AM to 9:00 AM and 4:30 PM to 11:00 PM.
- Honor Rancho Withdrawals minimized from 9:00 AM to 4:30 PM and 11:00 AM to 5:00 AM at rate of 195 MMcf/d
- La Goleta and Playa Del Rey withdrawals at constant levels of 221 MMcf/d and 114 MMcf/d respectively.
- Aliso Canyon assumed out of service with no withdrawals.

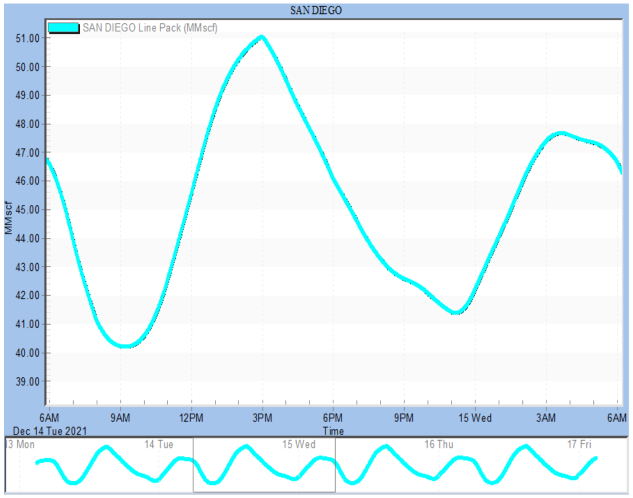
Portfolio 1: Gas Transmission System Expansion

Portfolio 1b - 2035 - Wheeler Ridge Supply/Expansions – Subsystems Line Pack

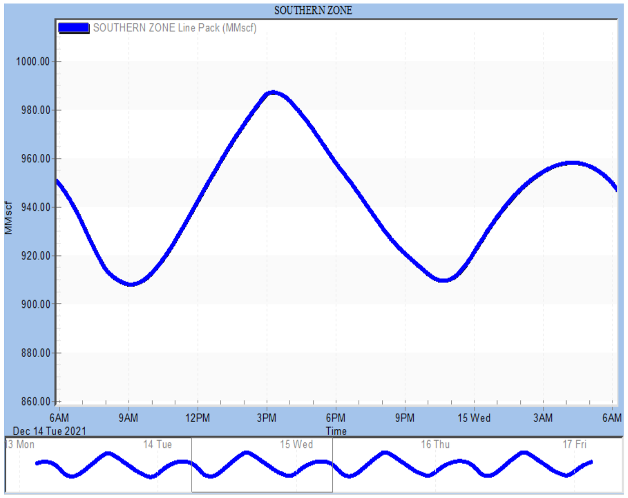
Coastal Zone



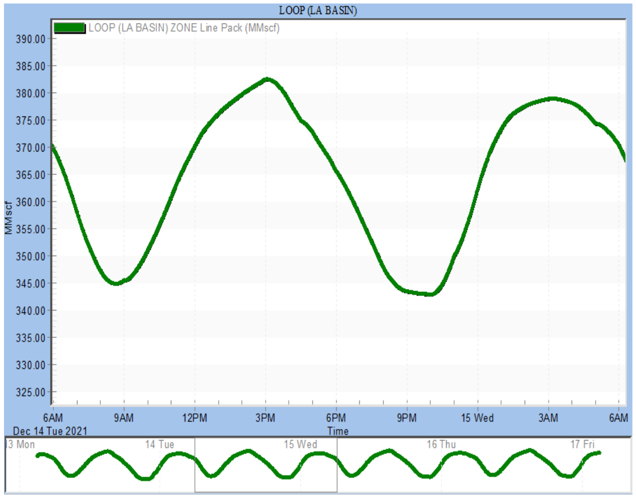
San Diego Zone



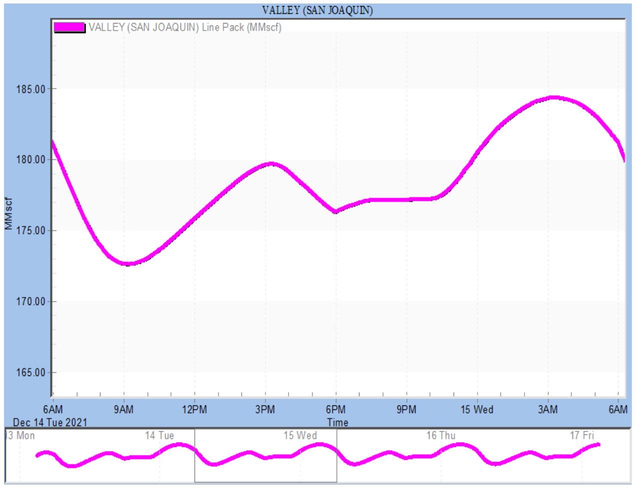
Southern Zone



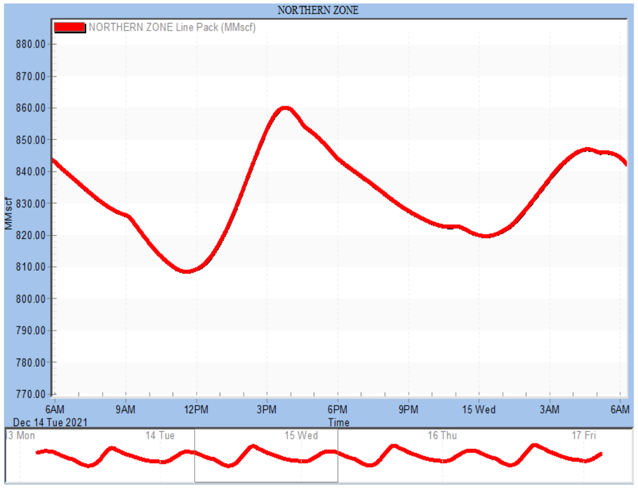
Loop (LA Basin) Zone



Valley (San Joaquin) Zone



Northern Zone



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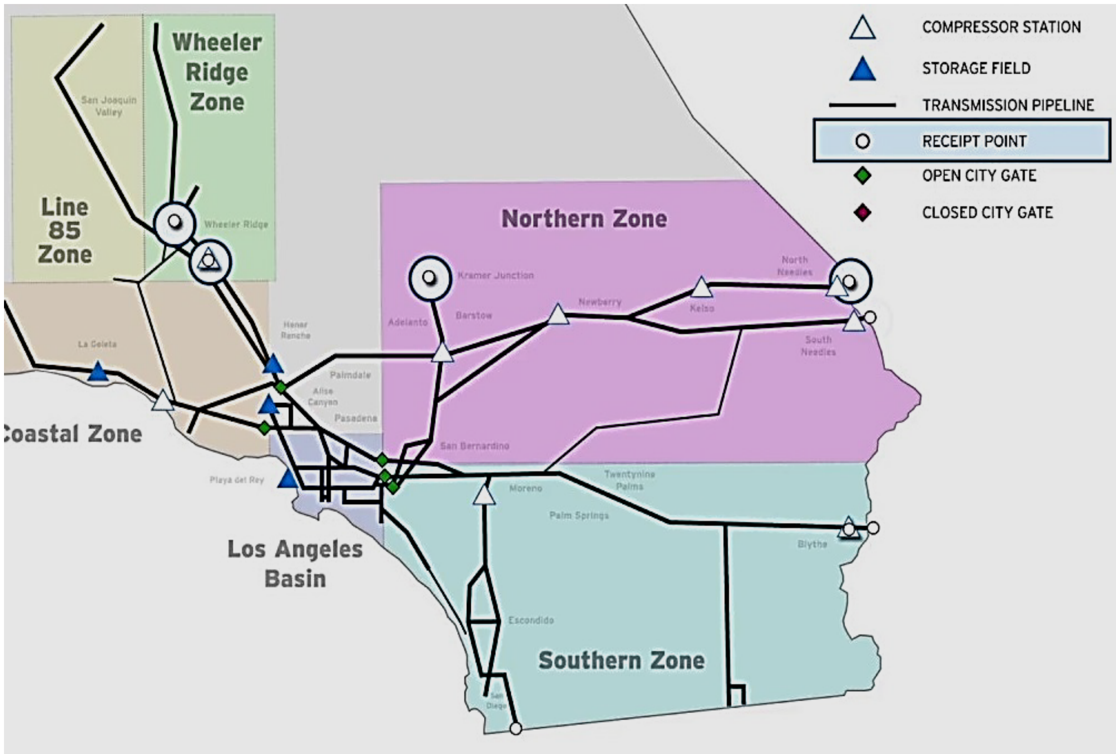
Portfolio 1: Gas Transmission System Expansion

Portfolio 1b - 2035 - Wheeler Ridge Supply/Expansions – Subsystems Line Pack



- **Line Pack recovers for ALL Zones in 2027 1-in-10 Demand Day Model with Adjusted Demand**

Zone	Day 1 – Midnight LinePack (MMscf)	Day 2 – Midnight LinePack (MMscf)
Coastal Zone	**333.8**	**334.6**
San Diego Zone	**42.2**	**42.5**
LA Basin Zone	**362.3**	**362.9**
Valley Zone	**180.5**	**180.6**
Northern Zone	**820.0**	**820.5**
Southern Zone	**921.6**	**922.6**

Appendix: CapEx / OpEx

Portfolio 1 CapEx/OpEx calculations

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Portfolio 1: Gas Transmission System Expansion

Cost Inputs: Portfolio 1a- Benchmark Level Capital Cost Estimates

Project 1a - 2027 – Northern Zone Supply / Expansions

Year	Project	Length (Miles)	Diam (in)	Benchmark Unit Cost ($2019MM)	Units	Total Cost ($2019MM)		O&M ($/Year) ($2019)
2027	Loop from North Needles CS towards Kelso CS	20	36	$ 8.9	$/Mile of 36”	$177.8		
	Loop from Kelso CS towards Newberry	15	36	$ 8.9	$/Mile of 36”	$133.4		
	Loop from Newberry towards Cajon Junction	48.5	36	$ 8.9	$/Mile of 36”	$431.3		
	Expand/ Rebuild Quigley Regulator Station	N/A	N/A	$ 3.4	Each	$ 3.4		
	Total Expansion Cost					**$ 745.9**		**$370,000**

Project 1a - 2035 – Northern Zone Supply / Expansions

Year	Project	Length (Miles)	Diam (in)	Benchmark Unit Cost ($2019MM)	Units	Total Cost ($2019MM)		O&M ($/Year) ($2019)
2035	Loop from North Needles CS towards Kelso CS	0	36	$ 8.9	$/Mile of 36"	$ -		
	Loop from Kelso CS towards Newberry	0	36	$ 8.9	$/Mile of 36"	$ -		
	Loop from Newberry towards Clajon Junctino	41.5	36	$ 8.9	$/Mile of 36"	$ 369.0		
	Expand/ Rebuild Quigley Regulator Station	N/A	N/A	$ 3.4	Each	$ 3.4		
	Total Expansion Cost					**$ 372.4**		**$190,000**

Portfolio 1: Gas Transmission System Expansion

Cost Inputs: Portfolio 1b- Benchmark Level Capital Cost Estimates

Project 1b - 2027 – Wheeler Ridge Supply/ Expansions

Year	Project	Length (Miles)	Diam (in)	Benchmark Unit Cost ($2019MM)	Units	Total Cost ($2019MM)		O&M ($/Year) ($2019)
2027	Loop from Wheeler Ridge South	34.8	36	$ 8.9	Mile	$ 309.4		
	Expand/ Rebuild Quigley Regulator Station	N/A	N/A	$ 3.4	Each	$ 3.4		
	Total Expansion Cost					**$ 312.9**		**$160,000**

Project 1b - 2035 – Wheeler Ridge Supply/ Expansions

Year	Project	Length (Miles)	Diam (in)	Benchmark Unit Cost ($2019MM)	Units	Total Cost ($2019MM)		O&M ($/Year) ($2019)
2035	Loop from Wheeler Ridge South	24.8	36	$ 8.9	$/Mile of 36"	$ 220.5		
	Expand/ Rebuild Quigley Regulator Station	N/A	N/A	$ 3.4	Each	$ 3.4		
	Total Expansion Cost					**$ 223.9**		**$190,000**

Portfolio 1: Gas Transmission System Expansion

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Cost Inputs: Support- Benchmark Cost Estimate Development (Capital Costs)

Development of Benchmark Pipeline Installation Cost – Capital Estimates

Sponsor	Project	Segment	Length (Miles)	Diameter (in.)	Total Estimated Cost	Estimate Dollars	CPI-U Escalator (to $2019)	Escalated Estimate ($MM - 2019)	$/in-diam-mile ($2019)
SoCalGas	North-South Project 1/	Adelanto-Moreno Pipeline	63	36	$ 484,545,193	$2014	108.0%	$523.27	$231,000
SDG&E	PSRP Project 2/	Line 3602 (Rainbow Station to Line 2010)	47	36	$ 426,800,000	$2015	106.5%	$454.63	$269,000
Weighted Average Cost (Benchmark)			**110**	**36**				**$977.90**	**$247,000**

1/ CPUC Docket A.13-12-013, SoCalGas Buczkowski Supplemental Testimony – Attachment A Filed November 2014.
2/ CPUC Docket A.15-09-013, SDG&E N. Navin Direct Cost and Schedule Workpapers Filed March 2016.

Development of estimated cost to expand/rebuild Quigley Regulator Station

SoCal Gas - 2011 Gas System Expansion Report filed December 8, 2011, pursuant to CPUC Decision (D.) 07-12-019

==>> All Expansion Scenarios Recommended "Replace Quigley Pressure Regulating Station"

From document….

- "A rebuild of the Quigley Station with a higher flow rate capacity will allow receipt of 1,265 MMcf/d at Wheeler Ridge"
- Estimated Cost for Quigley Rebuild in document was $3 Million ($2 Million Other-Labor and $1 Million Materials)
- 2011 Cost of $3 Million escalated by CPI-U escalator to $2019 ==>> ≈ $3,400,000

Portfolio 1: Gas Transmission System Expansion

Cost Inputs: Support – Portfolio 1b – Upstream Storage/ Transport Costs

Year	Service	Rate Schedule	2021 Annual Rate ($/Dth)	Expansion Capacity (MMcf/d)	Expansion Capacity (Dth/d)	Annual Cost ($2019)
2027	CGT - Mission Path to Off System (SoCalGas)	G-AFTOFF	$ 0.7294 [1/]	395	408,272	$108,690,000
2027	Cost of Storage Capacity (Based on PGE Costs)	Gill Ranch	[2/]			$21,570,000
2027	**Total Annual Upstream Service Costs**					**$130,260,000**
2035	CGT - Mission Path to Off System (SoCalGas) [1/]	G-AFTOFF	$ 0.7294 [1/]	323	333,853	$ 88,880,000
2035	Cost of Storage Capacity (Based on PGE Costs)	Gill Ranch	[2/]			$17,640,000
2035	**Total Annual Upstream Service Costs**					**$106,520,000**

[1/] Transportation Rate per California Gas Transmission EBB for “Mission Path” from PGE On-System Storage to SoCalGas Kern River Station

[2/] Annual Storage Costs projected based upon PGE Annual Costs as described below

Capacity Category	Injection (MMscf/day)	Inventory (Bcf)	Withdrawal (MMscf/day)	Annual Cost (2019$/Year) [(b)]
PGE Gill Ranch Capacity (a)	56	2.00	100	$5,461,000
Proposed SoCalGas Capacity (2027) (c)	221	7.90	395	$21,570,000
Proposed SoCalGas Capacity (2035) (c)	181	6.46	323	$17,640,000

(a) PGE Gill Ranch capacities per Table 3 of Pacific Gas and Electric Company 2019 GAS TRANSMISSION AND STORAGE RATE CASE WORKPAPERS SUPPORTING CHAPTER 11, NATURAL GAS STORAGE STRATEGY (NGSS) WORKPAPER FOR STORAGE SERVICES AND COST ALLOCATION

(b) PGE Gill Ranch Annual Costs per Tables 10-11 and 10-12 of Pacific Gas and Electric Company Chapter 10 Gas System Operations as included within PACIFIC GAS AND ELECTRIC COMPANY 2019 GAS TRANSMISSION AND STORAGE RATE CASE NOVEMBER 17, 2017 PREPARED TESTIMONY WITH ERRATA VOLUME 1 OF 2

(c) Proposed SoCalGas Capacity based upon withdrawal quantity equal to "shortfall" for given year and annual cost developed based upon gross up of PGE costs

Portfolio 1: Gas Transmission System Expansion

Cost Inputs: Support - Benchmark Cost Estimate Development (O&M Costs)

Development of Benchmark – Incremental Pipeline Operating Costs

Sponsor	Project	Segment	Incremental O&M Costs ($/Year)	Total Estimated Cost	Incremental O&M as % of Capital Cost
SoCalGas	North-South Project [1/]	Adelanto-Moreno Pipeline	$200,000	$ 484,545,193	0.04%
SDG&E	PSRP Project [2/]	Line 3602 (Rainbow Station to Line 2010)	$240,000	$ 426,800,000	0.06%
Average Incremental O&M Cost as % of Capital Cost					**0.05%**

[1/] CPUC Docket A.13-12-013, SoCalGas Buczkowski Supplemental Testimony – Attachment A Filed November 2014
[2/] CPUC Docket A.15-09-013, SDG&E N. Navin Direct Cost and Schedule Workpapers Filed March 2016