NW Natural's 2025 IRP- Technical Working Group

TWG # 6
Supply and Compliance Resources
January 28, 2025

NW Natural®

Forward Looking Statement

This press release, and other presentations made by NW Natural from time to time, may contain forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "assumes," “continues,” “could,” "intends," "plans," "seeks," "believes," "estimates," "expects," "will" and similar references to future periods. Examples of forward-looking statements include, but are not limited to, statements regarding the following: plans, objectives, assumptions, estimates, expectations, timing, goals, strategies, commitments, future events, gas supplies and infrastructure, pipeline transportation, storage and capacity, adequacy of gas supplies, customer rates, effects of weather, commodity costs, gas storage availability, adequacy and pricing, state carbon compliance programs and our ability to meet their compliance requirements, costs of and tools available for carbon compliance, renewable natural gas, carbon capture, alternative fuels, hydrogen, synthetic methane, tax credits, electrolysis, sequestration, plasma pyrolysis, carbon air capture, biomass, gasification, resource modeling, regional third-party projects, storage, pipeline and other infrastructure investments, competitive advantage, customer service, customer and business growth, business risk, efficiency of business operations, regulatory recovery, gas storage development, costs, timing or returns related thereto, financial positions and performance, economic and housing market trends, capital expenditures, strategic goals, greenhouse gas emissions, carbon savings, hedge efficacy, the regulatory environment, effects of regulatory disallowance, timing or effects of future regulatory proceedings or future regulatory approvals, regulatory prudence reviews, effects of regulatory mechanisms, effects of federal and state legislation, effects of local regulation, and other statements that are other than statements of historical facts.

Forward-looking statements are based on current expectations and assumptions regarding our business, the economy, geopolitical factors, and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Actual results may differ materially from those contemplated by the forward-looking statements. You are therefore cautioned against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future operational, economic or financial performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed by reference to the factors described in Part I, Item 1A "Risk Factors", and Part II, Item 7 and Item 7A "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosure about Market Risk" in the most recent Annual Report on Form 10-K and in Part I, Items 2 and 3 "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk", and Part II, Item 1A, "Risk Factors", in the quarterly reports filed thereafter, which, among others, outline legal, regulatory and legislative risks, public health risks, financial, macroeconomic and geopolitical risks, growth and strategic risks, operational risks, business continuity and technology risks, environmental risks and risks related to our natural gas business.

All forward-looking statements made in this report and all subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural, are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and NW Natural undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law. New factors emerge from time to time and it is not possible to predict all such factors, nor can it assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements.

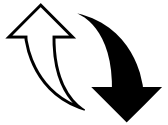
Today's Agenda

- Logistics
- Recap of previous TWG
- Objectives
- Supply-side Resources
  - Existing Resources
  - Future Resources
- Compliance Resources
  - State Policy Recap
  - Existing Resources
  - Future Resources

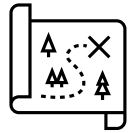
A 10-minute break will be provided during the Compliance Resources section

Facilitator Requests

Engage constructively and courteously towards all participants



Take space and make space



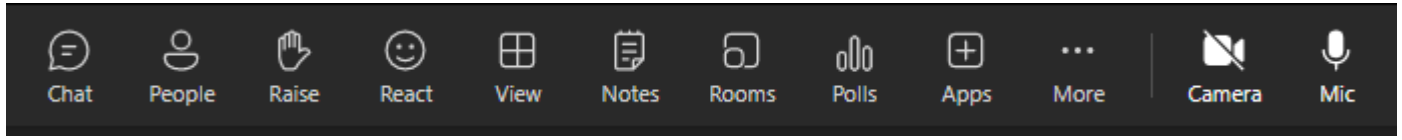
Respect the role of the facilitator to guide the group process

Avoid use of acronyms and help each other understand

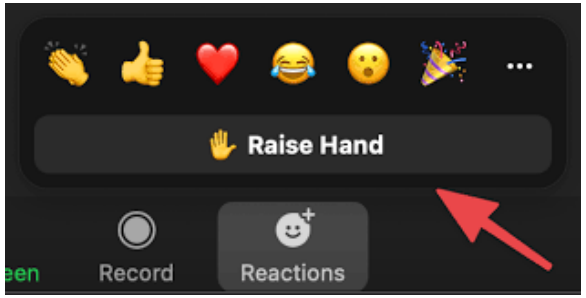
Aim to focus on the meeting topic

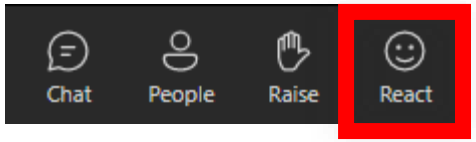
How to Interact in a Teams Meeting

- Participant Controls are at the top or bottom of your screen

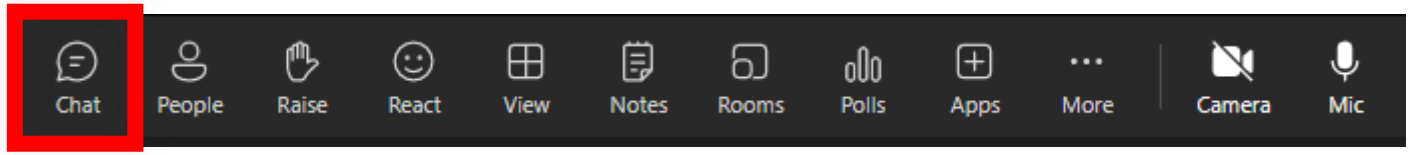


- Ask a question or comment at any time using the “raised hand”





- You may also use the chat box



A member of the IRP team will monitor the chat, and participant list for raised hands during the meeting.

Meeting Best Practices – virtual spaces

To maintain an engaged and productive space, please:

Mute your mic unless asking a question and/or providing comment

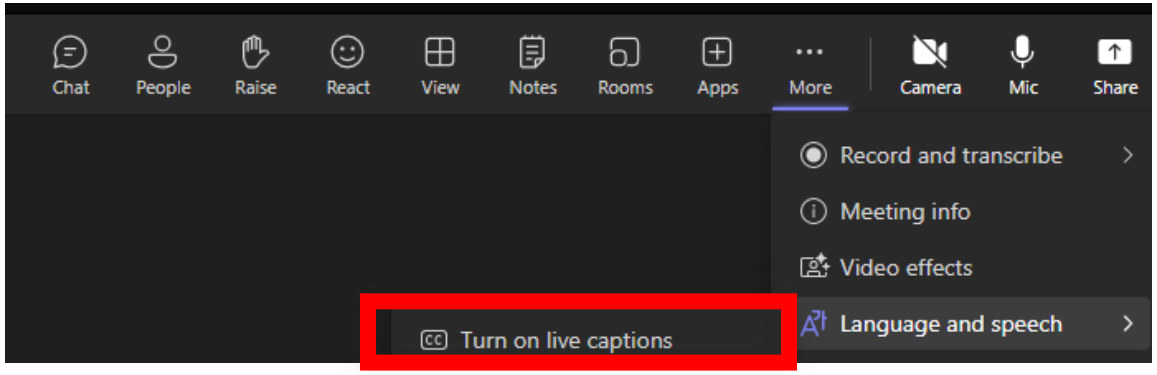
Turn your camera on when speaking (if you are comfortable and your bandwidth allows)

Limit side conversations in the chat

Make efforts to adhere to the meeting schedule

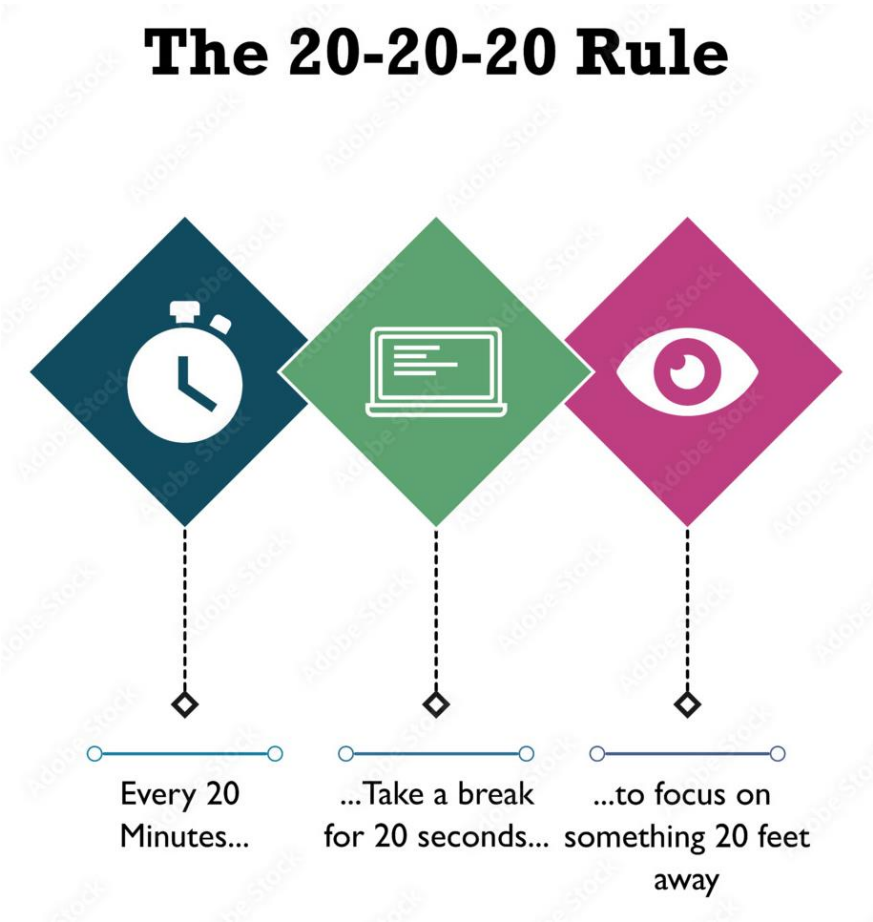
Teams Meeting – Accessibility Functions

- Live Captions - real-time auto-generated text of what is said in a meeting. They appear a few lines at a time for a user who has turned them on, and aren't saved



- Reducing Distractions and Customizing Views:
  - Microsoft Teams has a variety of features to support different learning styles, please find reference material for:
    - Turn on live captions during meetings
    - Customize your meeting view
    - Change background effects in Teams meetings
    - Reduce background noise in Teams meetings
    - 5 tips for using Teams when you're deaf or hard of hearing
- Meeting Recordings:
  - NW Natural will record IRP virtual meetings and will post them to the NW Natural website on the resource planning webpage

Take 2 Minutes for Safety: Prevent Eye Strain



- One main suggestion for reducing digital eye strain is to follow the 20-20-20 rule
- This rule says to take a 20-second break to view something 20 feet away from you every 20 minutes

Recap Jan. 21 TWG

- Shared information about avoided cost and demand-side resources
- Addressed clarifying questions about meeting topics
  - The variables that affect the resources used for compliance
  - The calculation method for avoided costs
  - The scale of energy savings from demand side resources

Today's objectives

- Share information about NW Natural's current resource portfolio
- Gain a shared understanding about potential resources NW Natural will consider for supply side and compliance requirements
- Address clarifying questions

Current Technical Working Group Schedule

TWG No.	Date	Type & Purpose of Engagement
TWG#1	Oct 22, 2024	**Planning Environment**
TWG#2	Nov 1, 2024	**Scenarios**
TWG#3	Nov 21, 2024	**Scenarios Cont. and Climate**
TWG#4	Dec 17, 2024	**Load Forecast**
TWG#5	Jan 21, 2025	**Avoided Costs & Demand-Side Resource**
TWG#6	Jan 28, 2025	**Supply-Side & Compliance Resources**
TWG#7	Apr 1, 2025	**TBA**
TWG#8	Apr 8, 2025	**Distribution System Planning**
TWG#9	Apr 29, 2025	**Resource Optimization Planning Model**
TWG#10	May 6, 2025	**Portfolio Results and Action Plan**
File Draft	Jun 13, 2025	**Comments due by July 7th**
File 2025 IRP	**Aug 2, 2025**	**Beginning of formal process**

- All TWGs will be facilitated and virtual
- Dates and topics are tentative and subject to change
- Please refer to website for most up to date information: IRP Website
- Feedback form direct link: Feedback Form
- Email us at IRP@nwnatural.com

Other Public Engagement Opportunities

Public Engagement Opportunity & Topic	Date	Type & Purpose of Engagement
Energy Resource (IRP) Fair #1:	November 16, 2024	**In-Person Only. Opportunity to learn and engage on IRPs and Energy Services & Programs. Event to be held in collaboration with community partners.** ***Parkrose High School from 11:00am to 2:00pm***
Public Engagement Webinar #1:	TBD	**Opportunity to learn and engage on an IRP and key topics previously presented and related to resource planning and utility energy services.**
Energy Resource (IRP) Fair #2:	May 10, 2025	**In-Person Only. Opportunity to learn about IRPs and Energy Services & Programs & Proposed Action Plan and engage. Event to be held in collaboration with community partners.**
Public Engagement Webinar #2:	TBD	**Opportunity to learn and engage on an IRP and key topics previously presented and related to resource planning and utility energy services.**

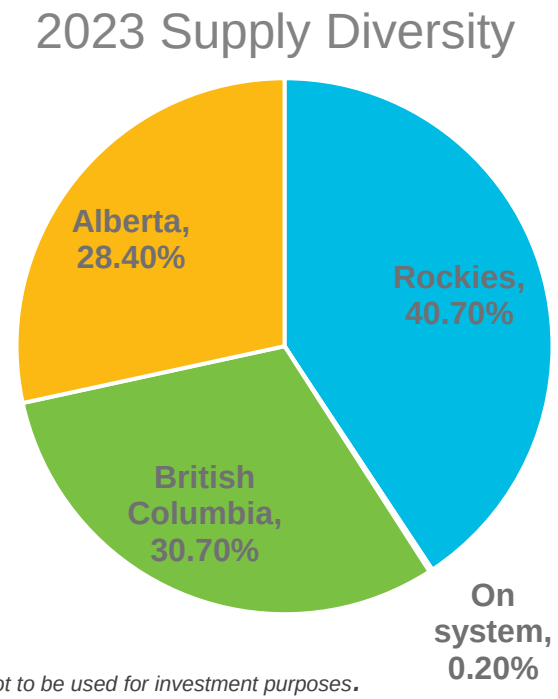
- Please check our dedicated IRP website for the most current information:

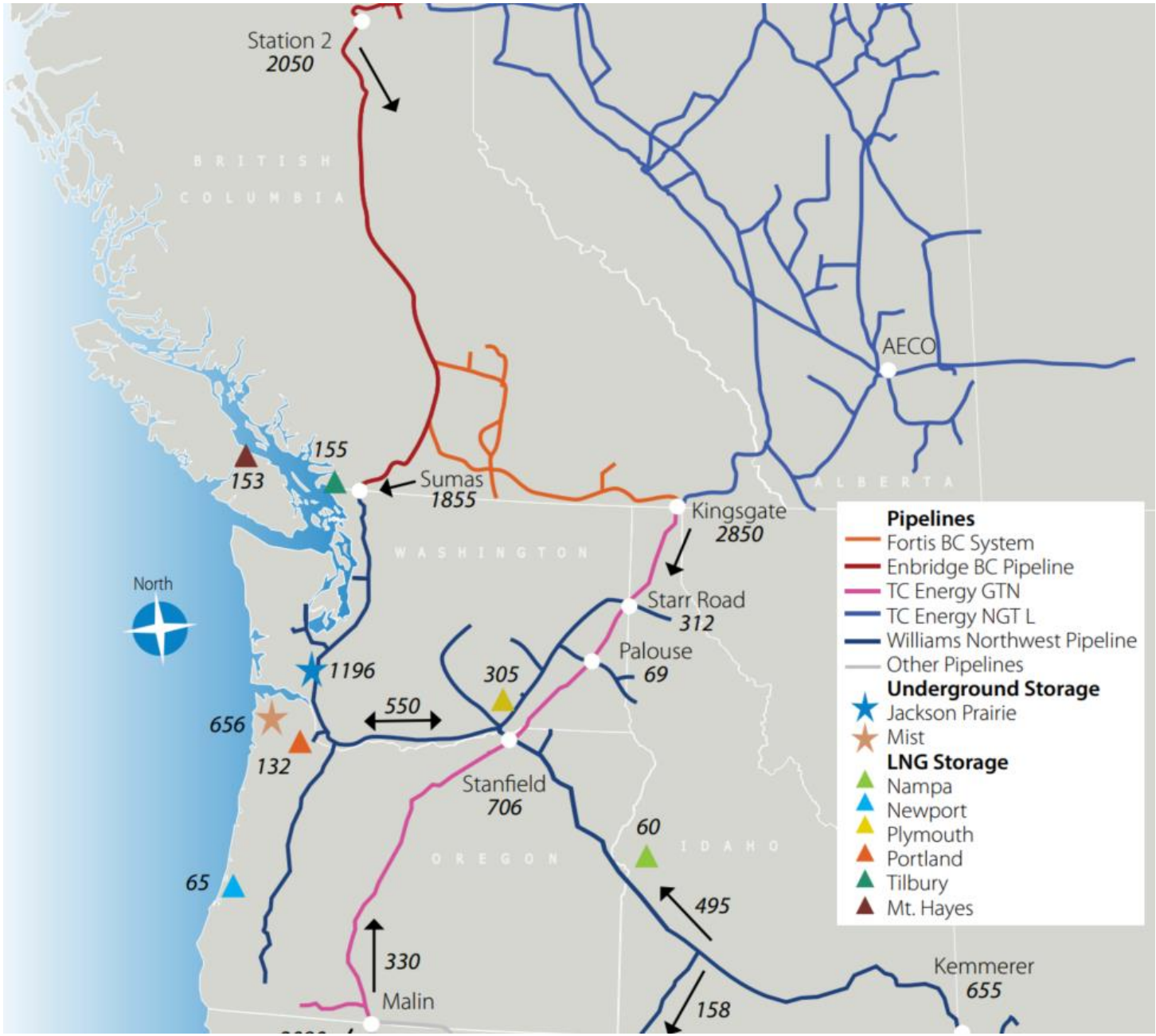
  IRP Website

Supply-Side Resources

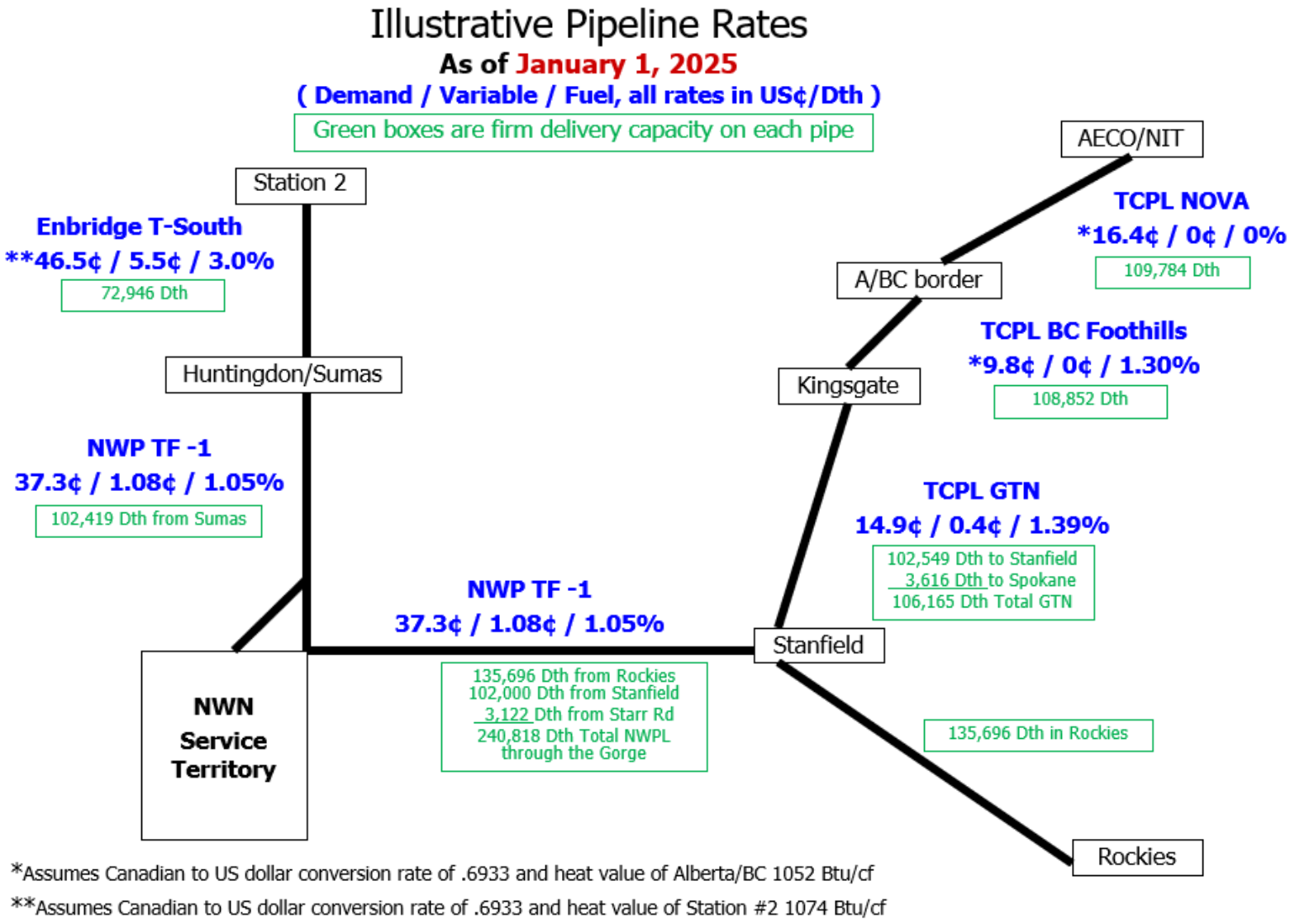
PNW Infrastructure

- NW Natural service territory is connected to Williams Northwest Pipeline
- We purchase natural gas from various upstream markets

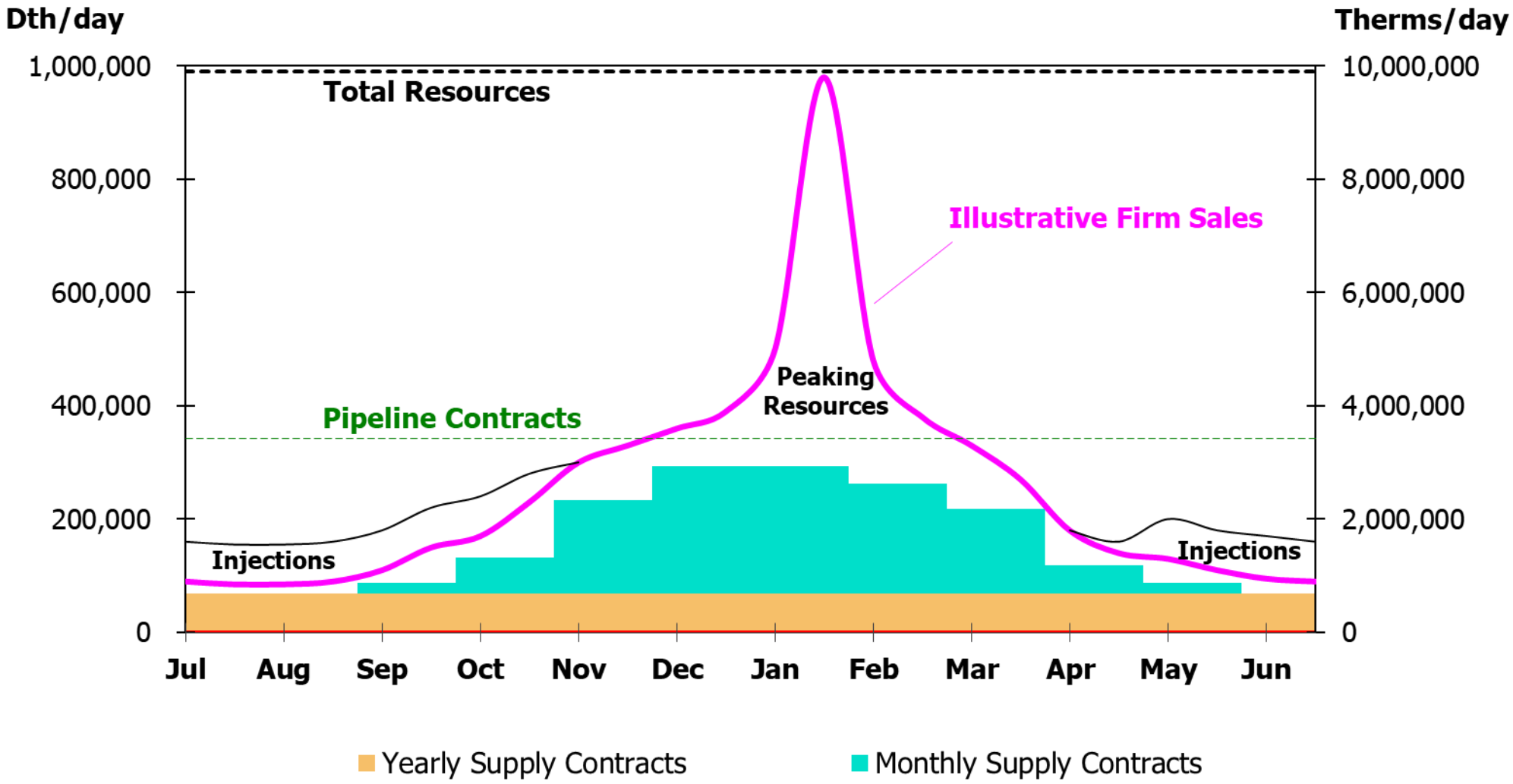




“Stick map” outlining NW Natural portfolio

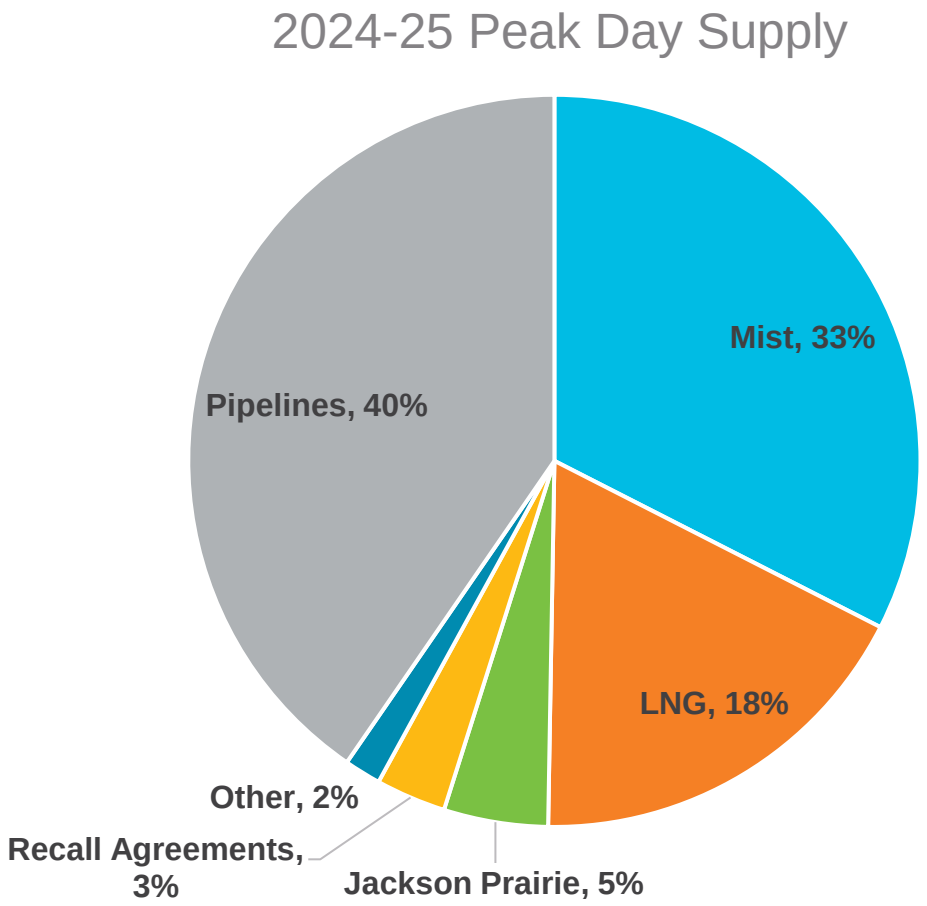


Our supply portfolio is designed to meet our year-round and peak-day needs



Gas Supplies are in place to serve peak demand of one million Dth this winter

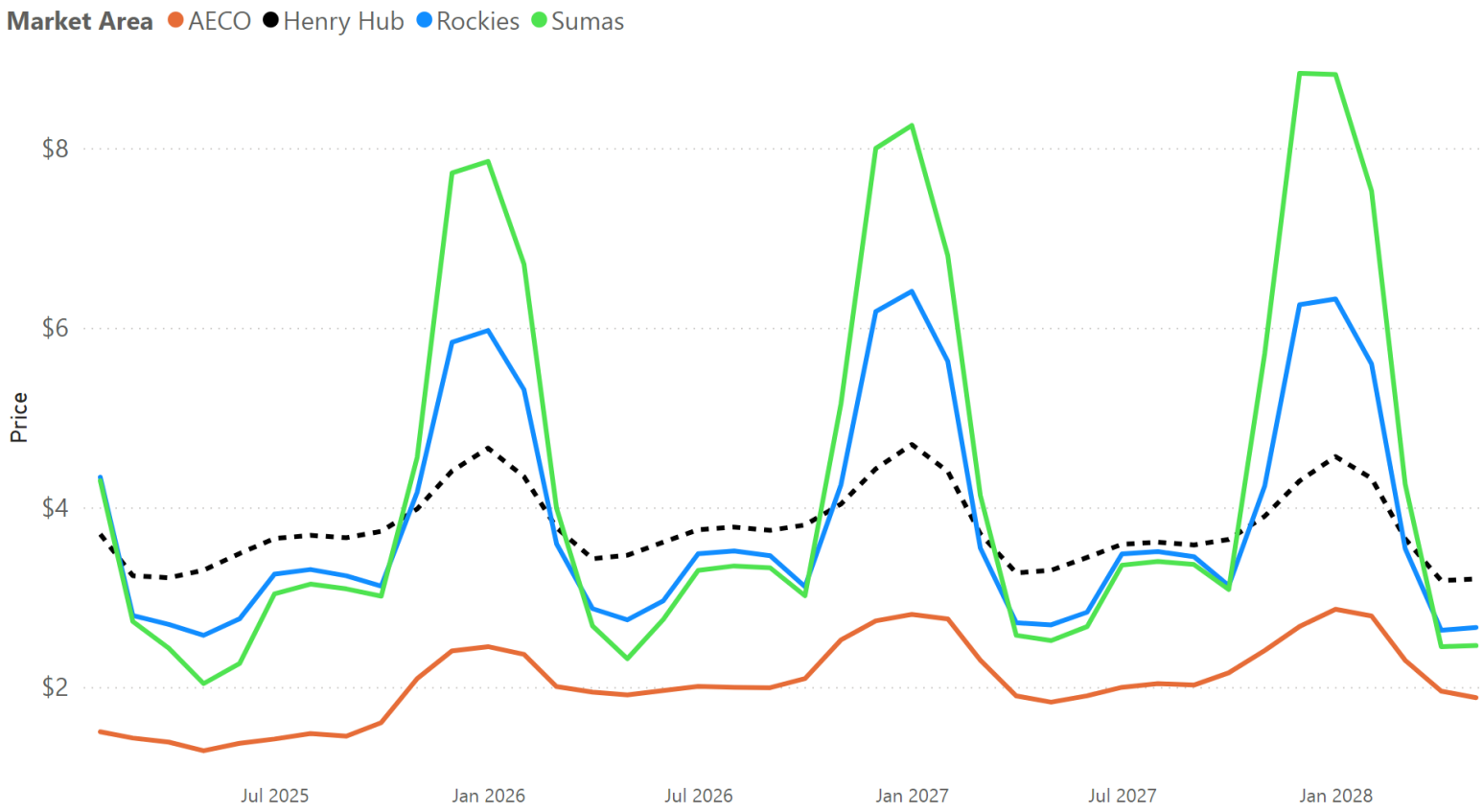
- Over half of our peak day supplies come from on-system storage, providing excellent resilience
- Our planning assumes all resources are available at their maximum output, so they need to be reliable
- Interruptible sales customers are also interrupted on peak days
- We had our first Mist recall since 2015 this year which increased the Mist allocation to customers



Our portfolio focuses on reducing customer bill impacts from volatile markets

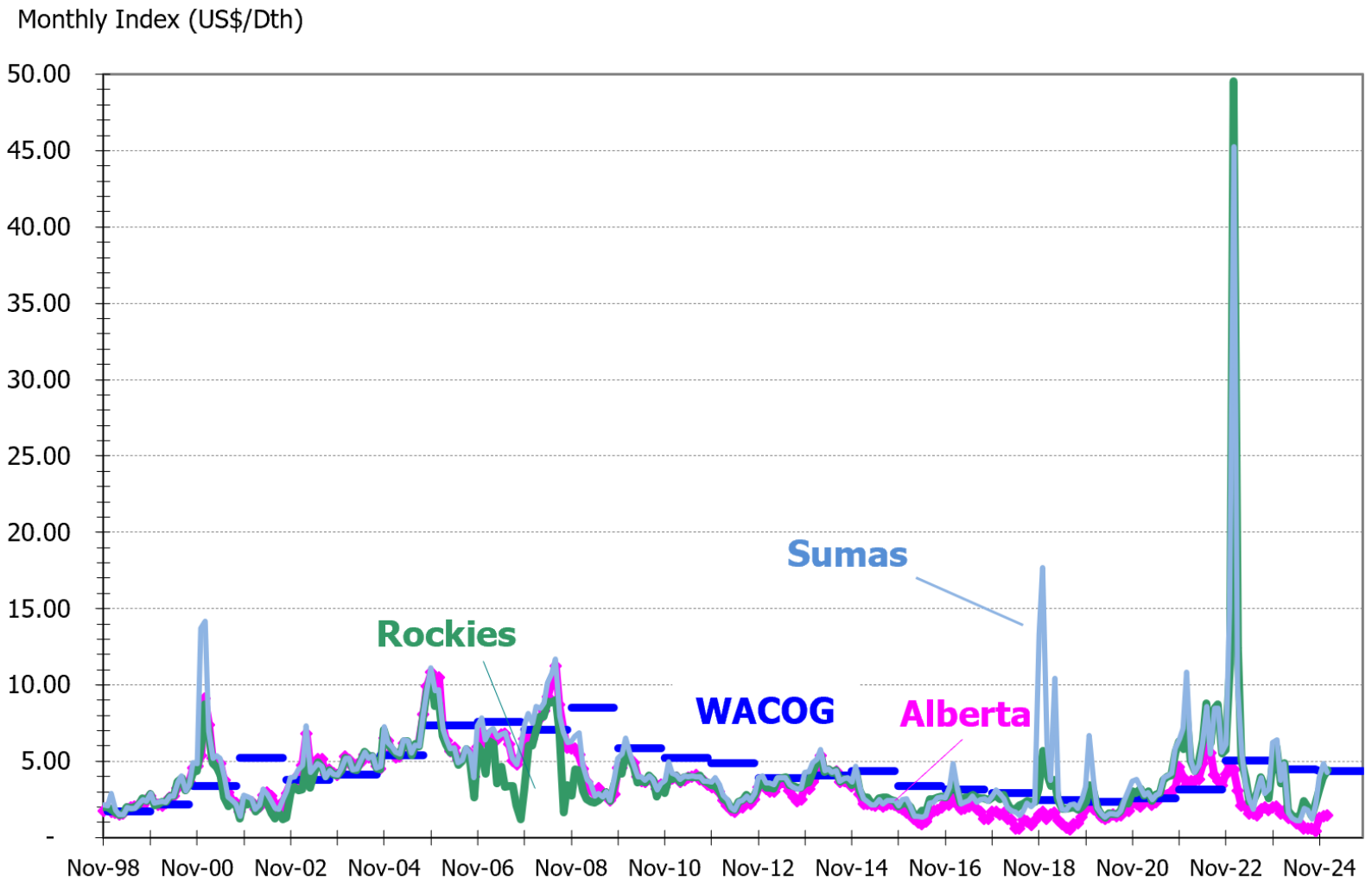
- Local markets continue to price in a winter risk premium due to constrained infrastructure, while AECO prices are low year-round
- NW Natural continues to target 85% hedging in Oregon
- Washington follows a risk based hedging program

January 9, 2025 pricing included in this graph



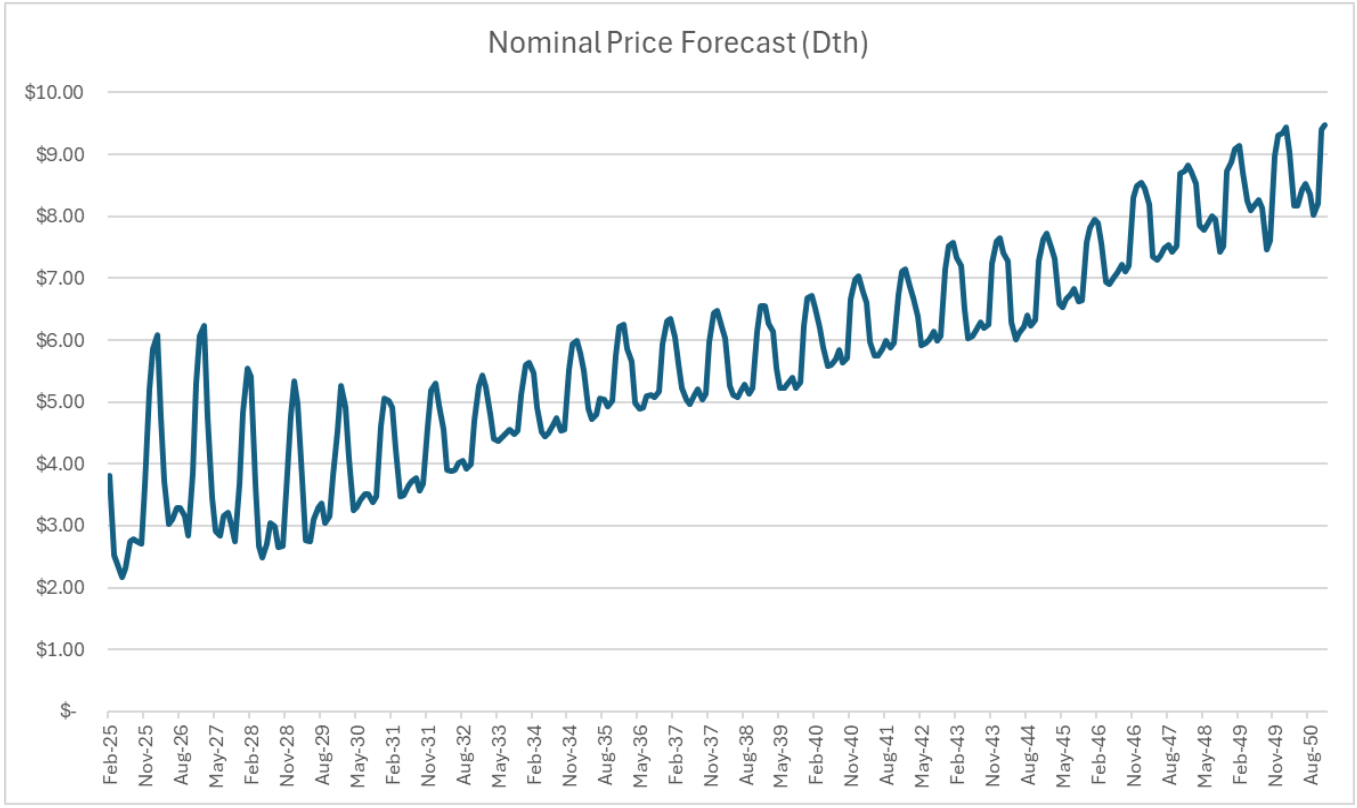
Commodity rates (WACOG bar) experienced by customers remain stable amidst market volatility

- This chart shows first-of-month prices, daily pricing is more volatile
- Weighted average cost of gas (WACOG) is Oregon specific
- Our hedging program protects customers from market spikes



We use a blended gas price forecast

- We rely on forward market prices and a third-party forecaster for our gas price forecast
- As there is high liquidity in the forward market in the near term, it bears more weight, while transitioning exclusively to the third-party forecast over time
- This price forecast will be updated at the end of February



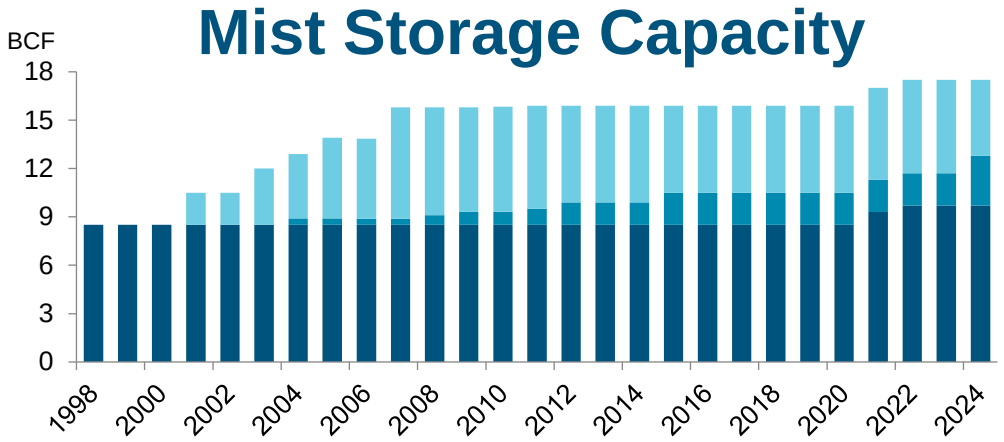
Mist Storage

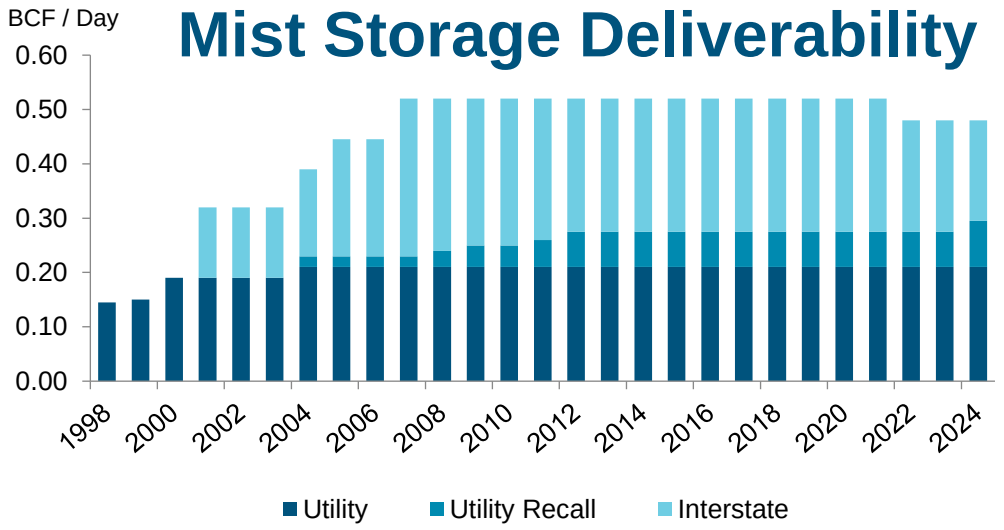
Overview

- In operation since 1989
- Storage capacity at Mist 17.5 Bcf
  - 12.8 Bcf Core Utility
  - 4.7 Bcf Interstate Storage Services

Unique, Valuable Asset

- Limited storage options in Pacific Northwest
- Part of utility's diverse, reliable gas supply strategy
- Utility can recall Interstate portion for Core Utility demand through IRP process
- Most recent recall was in 2024





Pacific Northwest gas system is very tight with more demand being added

- NW Pipeline system is designed as a 3.9 Bcf/day system
  - Flowed 4.5 Bcf on peak day in January 2024
- Utilization of NW Pipeline system exceeds 90% in winter months
- Natural gas used in regional power generation has increased over recent years
- Woodfibre LNG will have the impact of removing ~15% of the supply at the Vancouver, BC to Washington border beginning in 2027
  - Woodfibre has firm pipeline contracts which will take priority over other less firm shippers
  - NW Natural will cease reliance on segmented capacity for peak day requirements when Woodfibre comes online, removing 60,700 Dth from our peak day portfolio
    - This change may drive a large Mist recall

On-system Storage Resources

- Mist recall
  - As Mist is recalled at its depreciated net book value, it is a very low-cost option to fill portfolio needs
- Newport LNG
  - Another peak day supply option is to eliminate NW Natural system bottlenecks, allowing increased volumes of Newport LNG to flow on a peak day

Compliance Resources

State Carbon Compliance Programs

- Washington Climate Commitment Act (CCA)
- Oregon Climate Protection Program (CPP)

CCA Compliance Instruments & Pathways

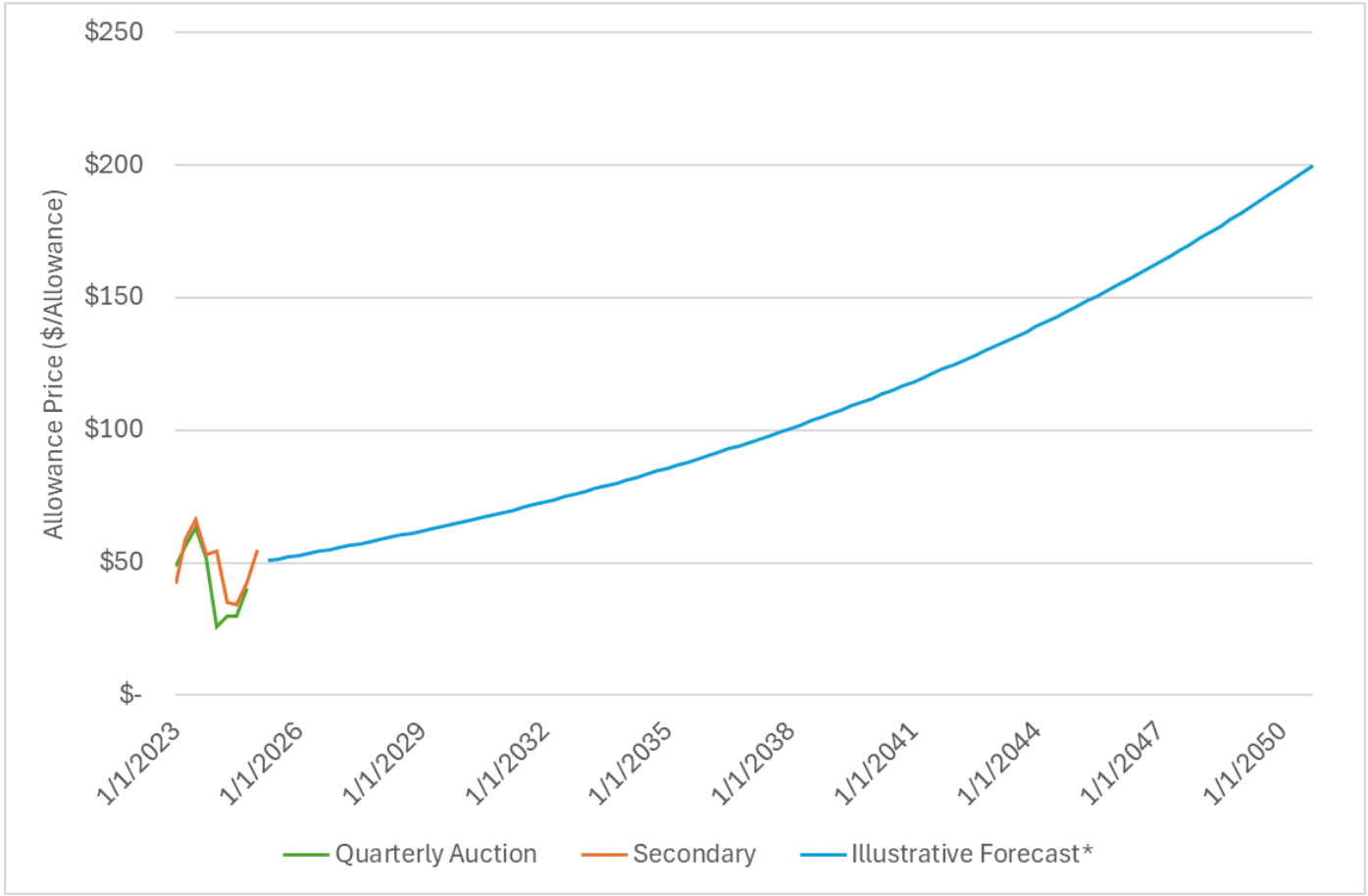
- Carbon Allowances
  - Western Climate Initiative Compliance Instrument Tracking System auction platform used to implement quarterly auctions and allowance price containment reserve auctions, when triggered
  - Limited market / aggressive trajectory cause high costs
- Eligible Carbon Offsets
  - Currently limited to projects benefitting WA - likely to change with linkage
  - Capped at 5% in 1st compliance period, unless inclusive of tribal offset projects, then up to 8% of obligation
- Customer Conservation & Low to No Carbon Gases
  - Energy Efficiency
  - Renewable Natural Gas and Hydrogen

CCA Auctions

- Quarterly Auctions:
  - Annual floor and ceiling price set
  - Allowances sold by state and consigned by natural gas LDCs or electric utilities
- Allowance Price Containment Reserve (APCR) Auctions:
  - Only held if the previous quarterly auction settled above the APCR Trigger Price
  - Up to four APCR Auctions per year
- Generated $1.8 billion dollars for the state of Washington in 2023
  - Funds are appropriated by the state legislature

Price Forecast of Washington Carbon Allowances

- Contracts with a third party that forecasts Washington allowances prices
- Allowances can be purchased in both Ecology quarterly auctions, Allowance Price Containment Reserve (APCR), auctions and secondary markets
- Allowance prices are currently around $53 per allowance
- Prices are forecasted to increase over time and range from $180-$220 by 2050

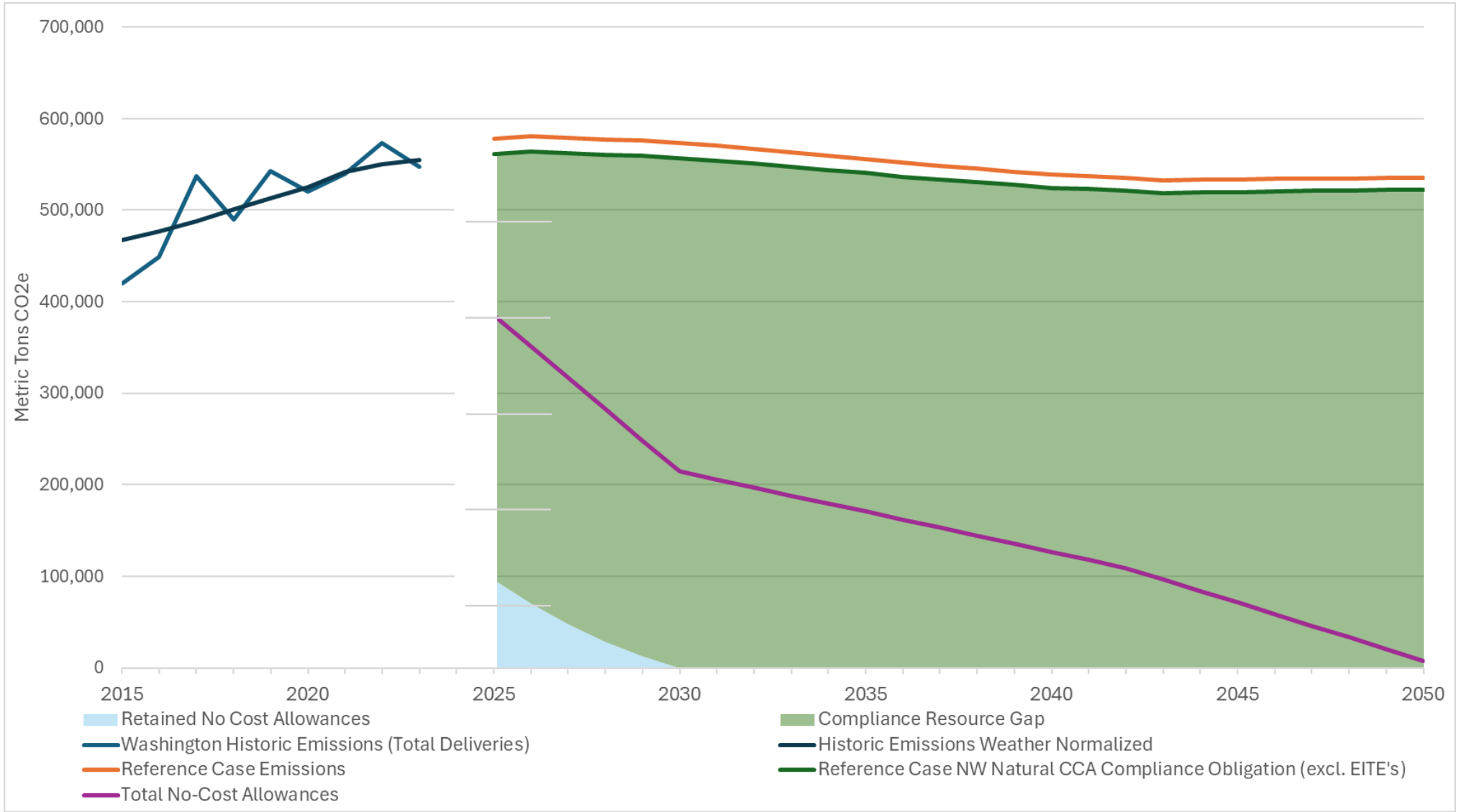


*Graph shows general trajectory of allowance prices. Allowance price forecast from third party is proprietary.

CCA Natural Gas LDC Specific Conditions

- Point of regulation for all customer emissions except for large sources (>25,000 mt CO2e) or EITE
- Receive some no cost allowances, but required to consign percentage of allowances to auction:
  - Starting at 65% in 2023 and increasing 5% up to 100% in 2030
- ***"Revenues from allowances sold at auction must be returned by providing nonvolumetric credits on ratepayer utility bills****, prioritizing low-income customers, or used to minimize cost impacts on low-income, residential, and small business customers through actions that include, but are not limited to, weatherization, decarbonization, conservation and efficiency services, and bill assistance"* **(CCA Bill Language, RCW 70A.65.130(2)(b))**

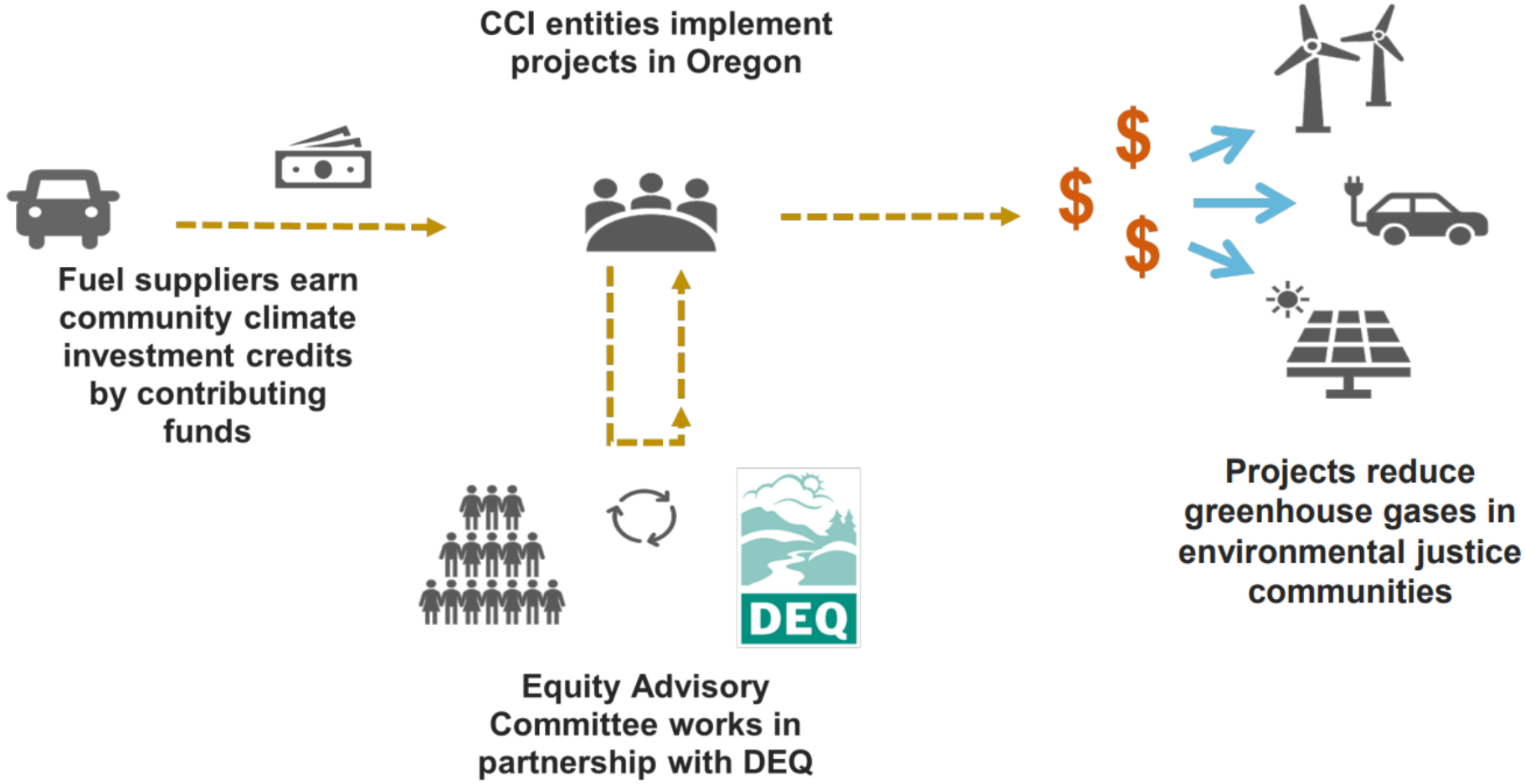
Washington Emissions Compliance Gap



Oregon CPP Compliance Tools

- Compliance Instruments
  - Distributed by the state (outlined in rule for LDCs)
  - Traded with covered entities
- Community Climate Investments (CCI)
- Energy Efficiency
- Renewable fuels
  - Biomethane (RNG)
  - Hydrogen
  - Synthetic Methane
  - Carbon Capture Utilization and Storage (CCUS)

CPP Community Climate Investments (CCI)

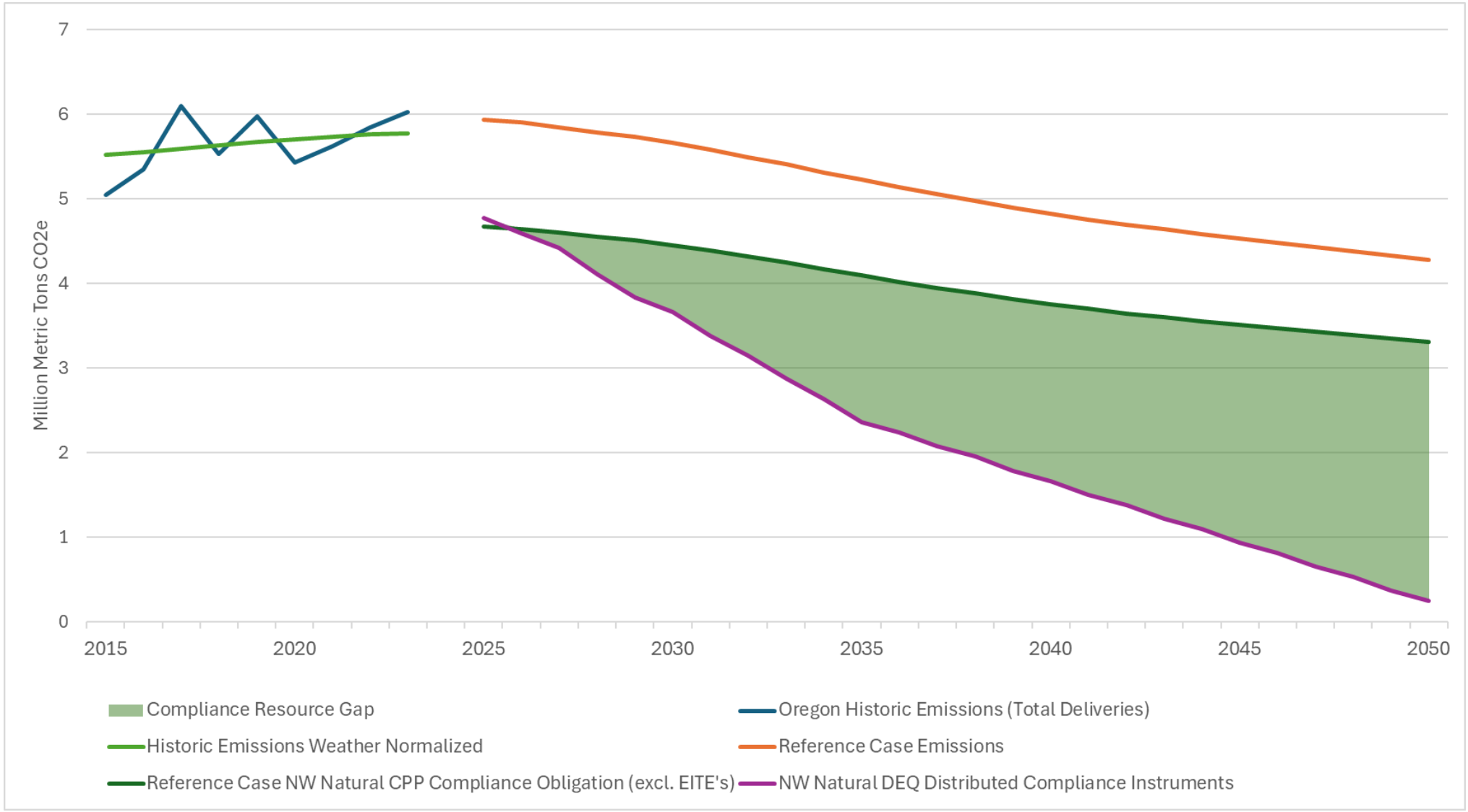


Source: [Department of Environmental Quality : Climate Protection Program 2024 : Rulemaking at DEQ : State of Oregon]

CPP Community Climate Investments (CCI) cont.

- Covered entities limited to 15% of compliance obligation in 1st compliance period, and 20% of compliance obligation in 2nd compliance period and beyond
- Unclear when CCI's will be available for purchase

Oregon Emissions Compliance Gap



Current RNG

Current RNG Resources

Procurement

(Pass-through Cost)

- **BP Products North America Inc. (formerly Archaea)** – Long term agreement, beginning in 2022, to purchase RTCs from a portfolio of landfill facilities
- **BP Products North America** – Beginning in 2022, purchase RTCs from a facility that produces organic waste
- **RNG Contract #1** – In 2025, RTCs from a TX landfill
- **RNG Contract #2** – Beginning in 2025, RNG from landfills in NC
- **Synthetic methane Contract #1** – 2 year pilot beginning in 2025

Investments

(Rate Base)

Partnership with Tyson Fresh Meats

- **Lexington Facility** – commenced operations in January 2022
- **Dakota City Facility** – commenced operations in April 2023

Confidentiality provisions limit the detail that can be provided here

1 Percentage is subject to change as projects are awarded, canceled or modified

NW Natural currently has exclusive rights to purchase RNG totaling about 3% of our annual sales volume for Oregon[1] and 1% for Washington[1]

RNG Procurement-Request for Proposal

- Verify General Qualifications
- Calculate Risk-adjusted Incremental Cost
  - Risk-adjusted incremental cost model for environmental attributes only
- Determine Short List
  - Order by risk-adjusted incremental cost
  - Proposals with the lowest 33% of incremental cost will move on to the next step
- Score Proposals
  - Incremental Cost (90%)
  - Local Economic Benefit (5%)
  - Contract Equity (5%)

Break – 10 Minutes

Alternative Fuels and Carbon Capture

Alternative Fuels and Carbon Capture Study

- From the last IRP the OPUC commission recommended that we hire a third party to evaluate the production costs and technical potential of Synthetic Methane
- NW Natural contracted with ICF to conduct this study for various alternative fuels and carbon capture in preparation for the 2025 IRP
  - Study was done in coordination with Avista and Cascade
  - ICF provides the technical potential and costs for these resources

Category	Type/Feed Stock
Renewable Natural Gas	Land Fill Gas
	Animal Manure
	Wastewater
	Food Waste
Hydrogen	Green from Dedicated Solar
	Green from Dedicated Wind
	Blue Hydrogen
	Turquoise Hydrogen
Synthetic Methane	Biomass
	Green from Dedicated Solar
	Green from Dedicated Wind
Carbon Capture Utilization and Storage	Industrial Customers
	Direct Air Capture

Technical Working Group Meeting

NW Natural – Alternative Fuels

January 28, 2025

Philip Sheehy
Director
Philip.Sheehy@ICF.com

Nima Simon
Manager
Nima.Simon@ICF.com

Harry Vidas
Vice President
Harry.Vidas@ICF.com

Andrew Griffith
Manager
Andrew.Griffith@ICF.com

Introduction

This presentation provides a summary of a detailed assessment done by ICF, a consultancy, of the levelized cost, resource potential, and carbon intensity of renewable natural gas (RNG), hydrogen, synthetic methane, and carbon capture and geologic storage (CCS) in Oregon and Washington

Fuels Studied

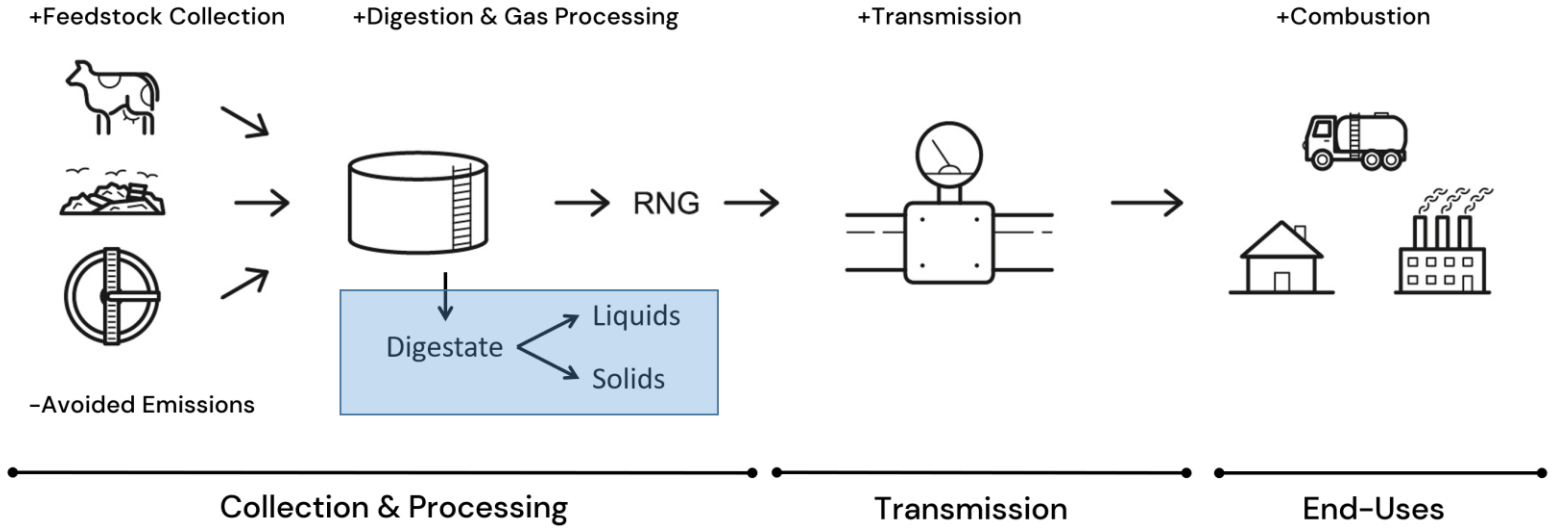
- **Renewable Natural Gas (RNG)** is derived from biomass or other renewable resources and is a pipeline-quality gas interchangeable with conventional natural gas. *Philip Sheehy presenting*
- **Hydrogen** is produced through various methods such as electrolysis, was assessed for its viability as a clean fuel. The analysis considered the technical advancements and cost implications of using hydrogen as a primary energy source. *Nima Simon presenting*
- **Carbon Capture, Use, and Storage (CCUS)** includes technologies for reducing emissions from current fossil fuel use that were analyzed for their effectiveness in capturing CO_2 and storing it underground. *Harry Vidas presenting*
- **Synthetic methane** is considered via two production pathways: a) thermal gasification of biomass and b) methanated electrolytic renewable hydrogen and CO_2. *Philip Sheehy presenting*

Note on costs: All costs are shown in real terms using $2024 unless otherwise specified

Renewable Natural Gas (RNG)

RNG production via anaerobic digestion

- Renewable natural gas (RNG) is a pipeline-compatible gaseous fuel derived from biogenic or other renewable sources that has lower lifecycle carbon dioxide equivalent emissions than geological (conventional) natural gas
- Produced via anaerobic digestion of waste feedstocks, including animal manure, food waste, landfill gas, and wastewater
- Microorganisms break down organic material to produce ‘biogas’ – a combination of methane, carbon dioxide and other constituents



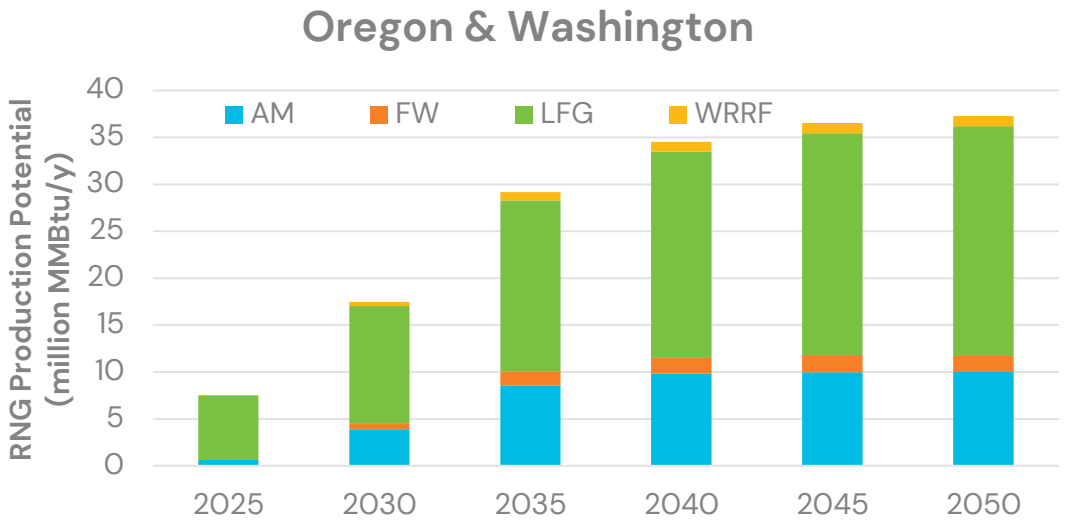
RNG – Feedstocks and Data Sources

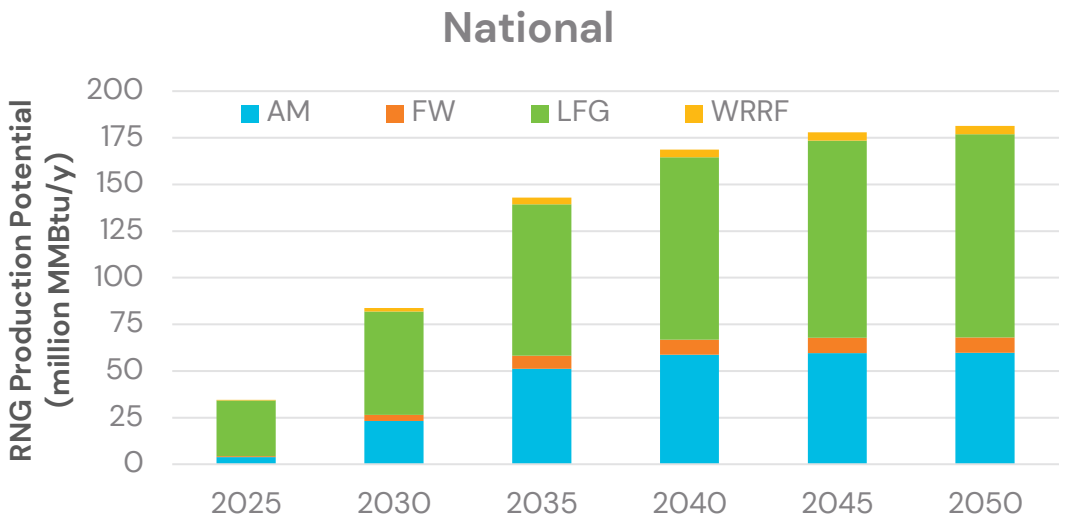
- Data sources vary by feedstock:
  - Feedstocks with facility-level information include LFG and WRRFs
  - Other feedstocks have county-level estimates for biomass
- Existing facilities with RNG potential can be aligned with current gas system and service territories
  - Other feedstocks can be aligned to service territories based on county-level data

Feedstock for RNG	Resources for Assessment
Animal manure 	Manure produced by livestock, including dairy cows, beef cattle, swine, sheep, goats, poultry, and horses.
Food waste 	Commercial, industrial and institutional food waste, including from food processors, grocery stores, cafeterias, and restaurants.
Landfill gas (LFG) 	The anaerobic digestion of organic waste in landfills produces a mix of gases, including methane (40–60%).
Water Resource Recovery Facilities (WRRFs) 	Wastewater consists of waste liquids and solids from household, commercial, and industrial water use; in the processing of wastewater, a sludge is produced, which serves as the feedstock for RNG.

RNG Resource Potential

- Derived estimates from a 2019 study that ICF completed for the American Gas Foundation (AGF 2019). Used the High Resource Potential case from that study
- OR/WA estimates are based on in-state production potential
- National estimate is the population-weighted *share* of the national pool of RNG resource to which NW utilities are expected to have access
  - Actual RNG production capacity today is around 100 million mmBtu
- Assumed that these feedstocks are used in anaerobic digestion pathways to produce RNG
  - No assumptions regarding mixed digesters





Note different scales of figures

Levelized cost of gas (*LCOG*) for RNG

Capital Costs

Facility Sizing
- Differentiate by feedstock
- Prioritize larger facilities to the extent feasible

Gas Conditioning & Upgrade
- Vary by feedstock and technology

Compression
- Capital costs for compressing the conditioned/upgraded gas for pipeline injection

+

O&M Costs

Operational Costs
- Operational Costs for each equipment type including utility charges for estimated electricity and natural gas consumption

Feedstock
- Feedstock costs
- Can be revenue rather than cost e.g., via tipping fees

Delivery
- Financing, constructing, and maintaining a pipeline to deliver RNG: $1 to $5/mmBtu

=

Levelized Cost of Gas $/mmBtu

- Calculated based on the initial capital costs in Year 1, annual operational costs discounted, and RNG production discounted accordingly over a 20-year project lifetime

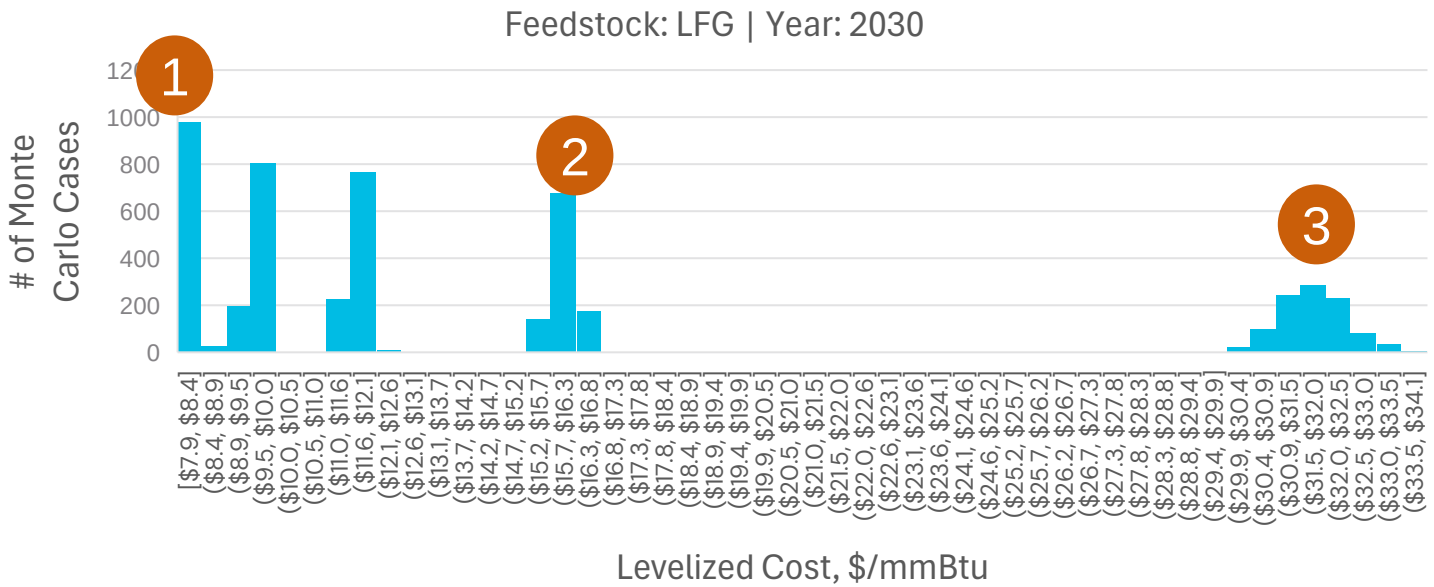
Example: Animal Manure (Dairy)

- *Cannot* capture on-the-ground drivers that lead to cost variation
- Represent capital expenditures (CapEx) as best as possible—default to conservative cost estimates (i.e., higher cost)
- Operations and maintenance (O&M) expenditures can vary significantly, but values are informed by ICF analysis of dozens of projects
  - Covered lagoon vs purpose-built digester

Cost element	Small facility	Large facility
Facility sizing	22,000 MMBtu/y (90 scfm)	320,000 MMBtu/y (1300 scfm)
Capacity factor	90-95%	
Installation costs	40% of capex	
CapEx ($m)	$6.10	$28.30
Pipeline ($m)	$2.0	
Utility interconnect ($m)	$3.0	
O&M, equipment	10-20%	
O&M, electricity	35 kWh/MMBtu	
O&M, natural gas	35% MMBtu/MMBtu	
Financial parameters	20 year term | 4% WACC	

LCOG results for RNG from LFG, 2030

1. Projects already deployed here; most of resource is in this range
2. Next wave of LFG projects
3. Smaller landfills with higher cost



RNG Levelized Cost Projection Base Case Results

- Broad range reflects variation across project-types
- Landfill gas is most cost-effective resource (no need to build the digester!)
- Wastewater can also be a cost-effective resource
- Food waste requires pre-processing; increases cost
- Small animal manure projects are high end of cost range

Oregon and Washington

RNG Feedstock	2025	2050
Animal Manure	$35-$119	$50-$172
Food Waste	$42-$81	$61-$119
Landfill Gas	$7-$30	$10-$42
Water Resource Recovery Facilities	$10-$44	$12-$59

National ($/MMBtu)

RNG Feedstock	2025	2050
Animal Manure	$36-$120	$51-$172
Food Waste	$43-$83	$62-$120
Landfill Gas	$8-$31	$10-$43
Water Resource Recovery Facilities	$11-$45	$13-$60

Hydrogen

Hydrogen Production Methods

Hydrogen Feedstock	Production Technology	Former Color
Natural Gas	Hydrogen produced from SMR, no CCS	Gray
Coal	Hydrogen produced from coal gasification	Brown
Natural Gas	Hydrogen produced from SMR/ATR with 97%+ CCS	Blue
Natural Gas & RNG	Hydrogen produced from SMR/ATR with 97%+ CCS	Blue
RNG	Hydrogen produced from methane pyrolysis	Turquoise
Natural Gas	Hydrogen produced from methane pyrolysis	Turquoise
Renewable Electricity	Hydrogen produced via electrolysis from renewable energy	Green
Nuclear Energy	Hydrogen produced via electrolysis from nuclear energy	Pink

- Current most widely used method of mass production of hydrogen is **steam methane reforming (SMR). Autothermal reforming (ATR)** is a similar process which involves oxygen instead of air mixed with fuel
- **Carbon capture and sequestration (CCS)** can be added at the backend of an SMR or ATR process to reduce the carbon intensity of the hydrogen production process
- Electrolysis and pyrolysis are other methods of “low carbon” hydrogen production

Levelized Cost of Hydrogen (LCOH) Model

Capital Cost Inputs:

- Facility size
- Learning curve rate or technology improvements over time
- Assumptions on weighted average cost of capital (WACC) & loan duration for project financing

Operational Cost Inputs:

- Natural gas pricing (Henry Hub)
- RNG pricing (from RNG model)
- Electricity pricing (2023 EIA's Annual Energy Outlook (AEO) report or National Renewable Energy Laboratory (NREL))
- Water cost (U.S. Department of Energy Office of Scientific and Technical Information)
- Technology energy and water consumption rates
- Maintenance & labor assumptions

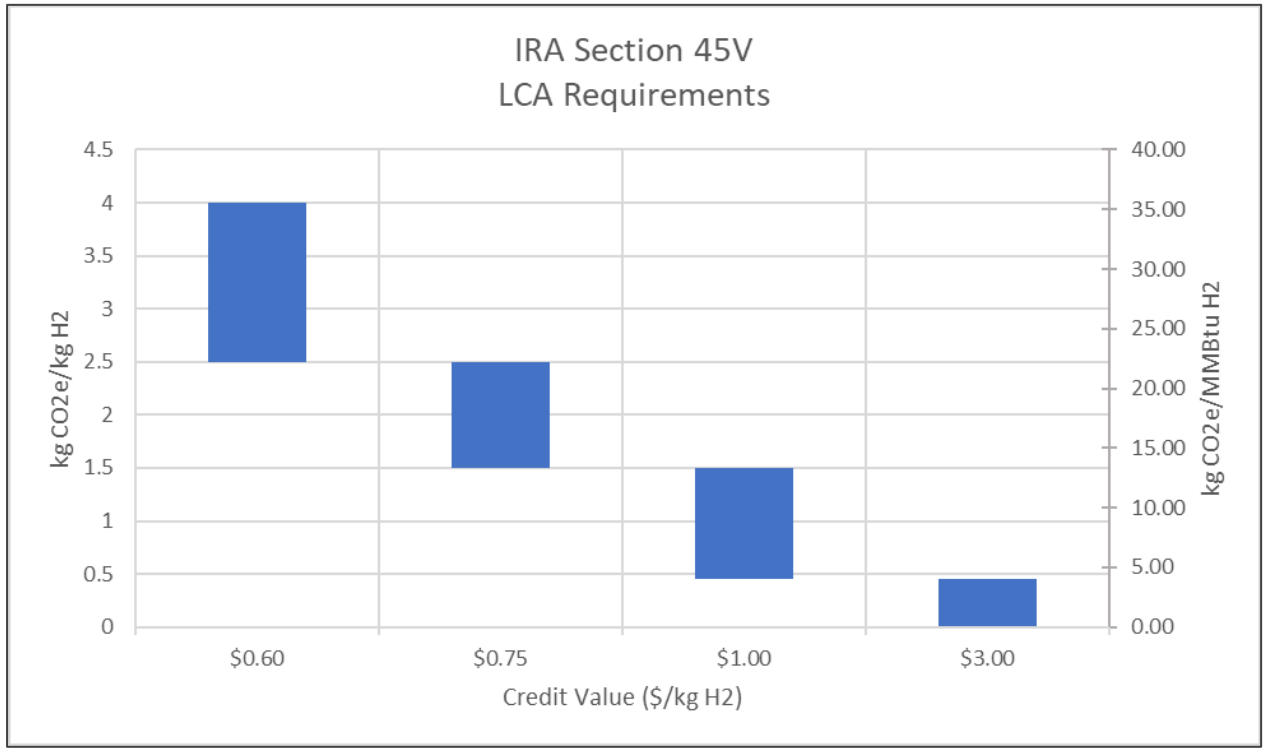
Resource Constraint:

- Annual forecasts from solar, wind and nuclear power from AEO
- Variable percentage of resources dedicated to hydrogen production
- Natural gas & RNG assumed to be accessible

Technology Readiness:

- Projection of hydrogen projects to come online based on project announcements within the region (OR and WA) and in nearby states

Hydrogen Cost Model – Tax Credit Incentives



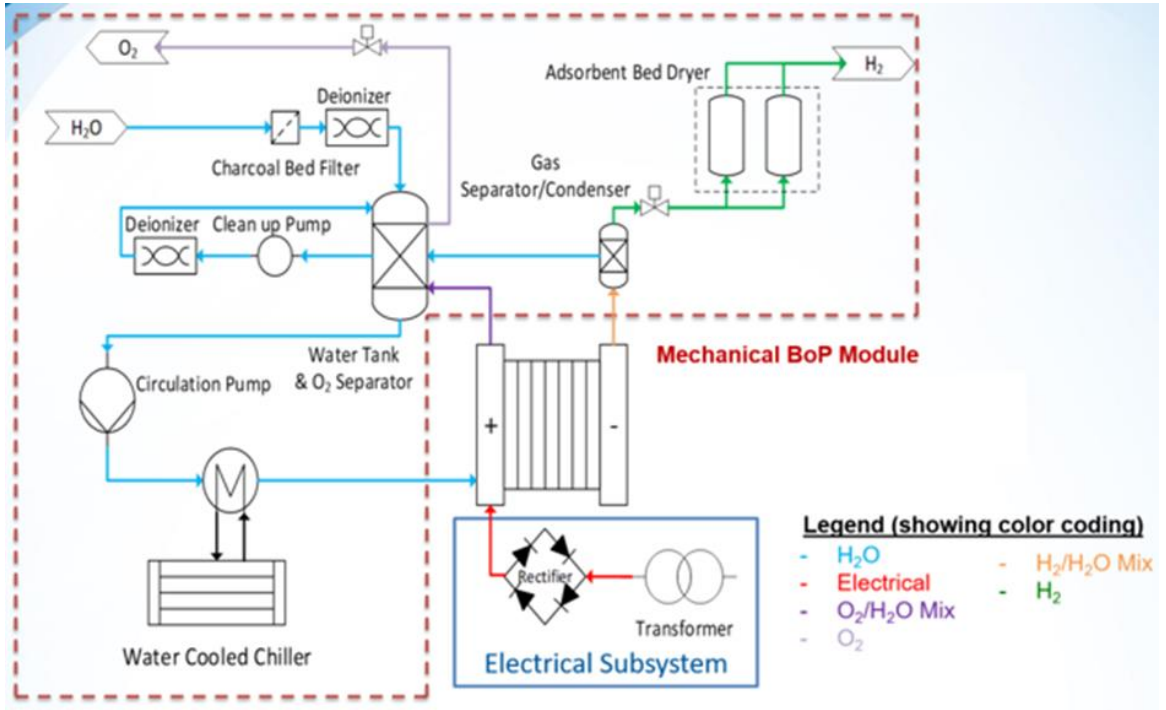
Incentives: Inflation Reduction Act (IRA)

- Clean Hydrogen Production Tax Credit (Section 45V) is dependent on the lifecycle analysis (LCA) of the hydrogen production
- 10-year incentive with maximum credit of $3/kilogram of hydrogen (kg H2) if LCA is 0.45 carbon dioxide equivalent /kilogram hydrogen (kg CO2e/kg H2) or 3.96kg CO2e/million British thermal units (kg CO2e/MMBtu H2)

Hydrogen Cost Model – Electrolysis

Electrolysis

- Proton Exchange Membrane (PEM) system
  - Solid polymer electrolyte
  - Operating temperature: 50-80 degrees Celsius
  - Stack life: 20,000 – 60,000 hours
- Model Results
  - Target Facility Size: 220MW (~20 million kg/yr)
  - Summary of the range of regional (OR and WA) and national results for 2050:
    - Technical potential for 2050: 45-95 thousand MMBtu/year for regional and 3,800- 7,800 thousand MMBtu/year for national
    - Cost Ranges for 2050:



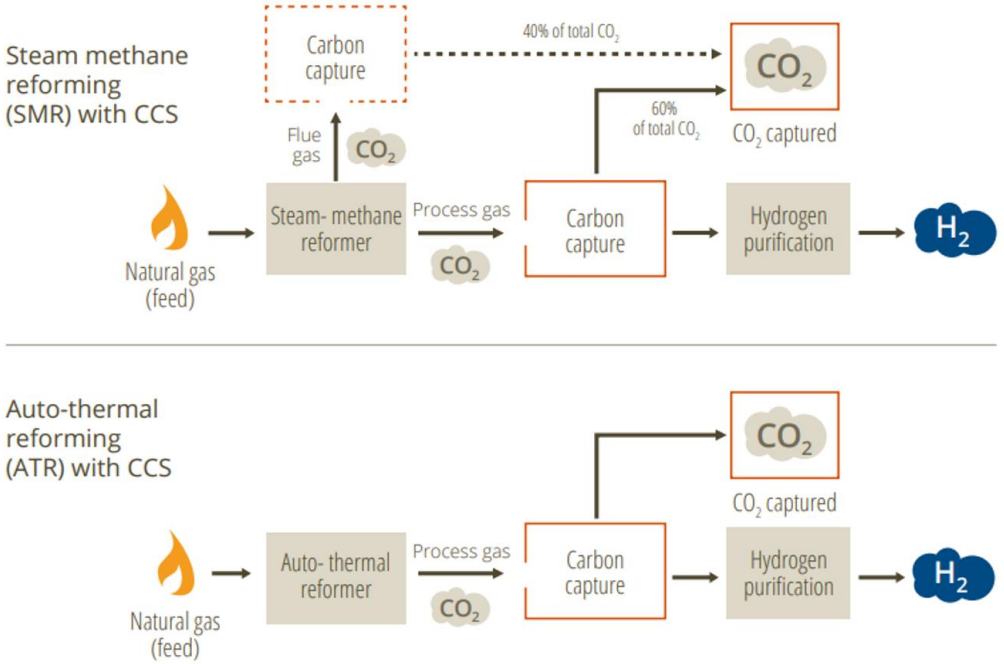
Source: DOE

	Regional $/MMBtu	National $/MMBtu
Electrolysis + Solar	$30-$41	$31-$43
Electrolysis + Wind	$40-$61	$39-$59

Hydrogen Cost Model – ATR with CCS

Autothermal Reformer (ATR) with Carbon Capture and Sequestration (CCS)

- Facility Size: ~8,900 kg/h (92% plant utilization)
- Carbon capture percentage: 97%
- Blend of RNG with natural gas to reduce carbon intensity to 0.45kg CO2e/kg H2
  (Note: analysis was completed prior to 01/2025 Section 45V guidance updates)
- Summary of the range of regional and national results for 2050:
  - Technical potential for 2050: 130-265 thousand MMBtu/year for regional and 16,500- 33,500 thousand MMBtu for national
- Cost Ranges for 2050:



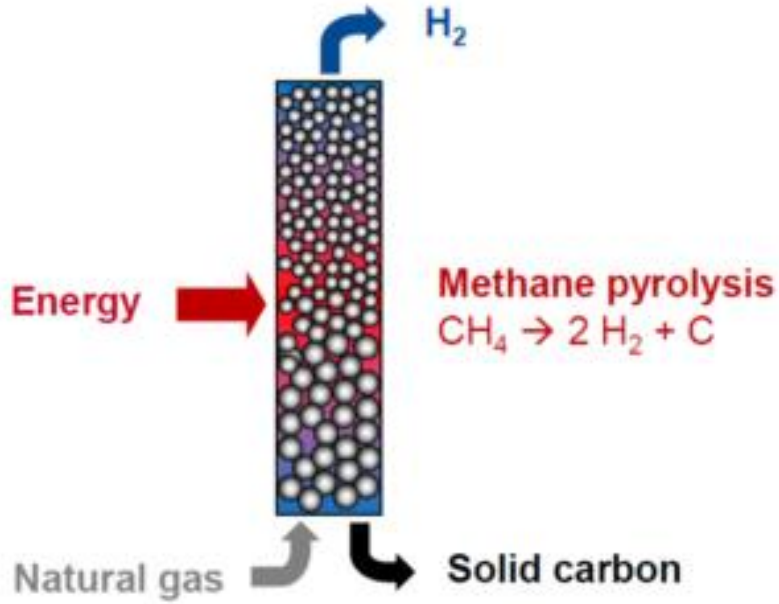
Source: Pembina Institute

	Regional $/MMBtu	National $/MMBtu
ATR with CCS	$24-$31	$24-$31

Hydrogen Cost Model – Plasma Pyrolysis

Plasma Pyrolysis

- Facility Size: 1,000 kg/d (93% plant utilization)
- Carbon black yield: 3kg carbon black/kg hydrogen
- Blend of RNG with natural gas to reduce carbon intensity to 0.45kg CO2e/kg H2
  (Note: analysis was completed prior to 01/2025 Section 45V guidance updates)
- Summary of the range of regional and national results for 2050 for a microwave pyrolysis facility:
  - Technical potential for 2050: 95-195 thousand MMBtu/year for regional and 16,500- 33,500 thousand MMBtu for national
- Cost Ranges for 2050:



Source: Ammonia Energy Association

	Regional $/MMBtu	National $/MMBtu
Plasma Pyrolysis	$29-$52	$31-$54

Hydrogen Levelized Cost – Storage & Transportation

- Currently, ~1,600 mi of hydrogen pipeline in the U.S. according to the U.S. Department of Energy
- Based on the NREL/Gas Technology Institute (GTI) Study, the technical capabilities of hydrogen blending in natural gas pipeline are
  - Up to 50% H2 flowing through transmission pipelines, and
  - Up to 20% H2 flowing through distribution pipelines
- Estimated cost of a new 100% hydrogen pipeline range from $0.20-$1.70/MMBtu per 50 miles depending on diameter and flow capacities
- The underground storage, liquefaction and cryogenic tank costs were annualized over a 20-year period with a 9% interest rate for storage in large cryogenic tanks and estimates for trucking hydrogen were taken from literature
  - Approximately $4-5/MMBtu for gas storage in a salt cavern or $1/MMBtu for liquid storage in a cryogenic tank (excluding the cost of liquefaction ~30-35/MMBtu for liquefaction depending on electricity cost)
  - For trucking: ~$2.29/MMBtu for 100 mi

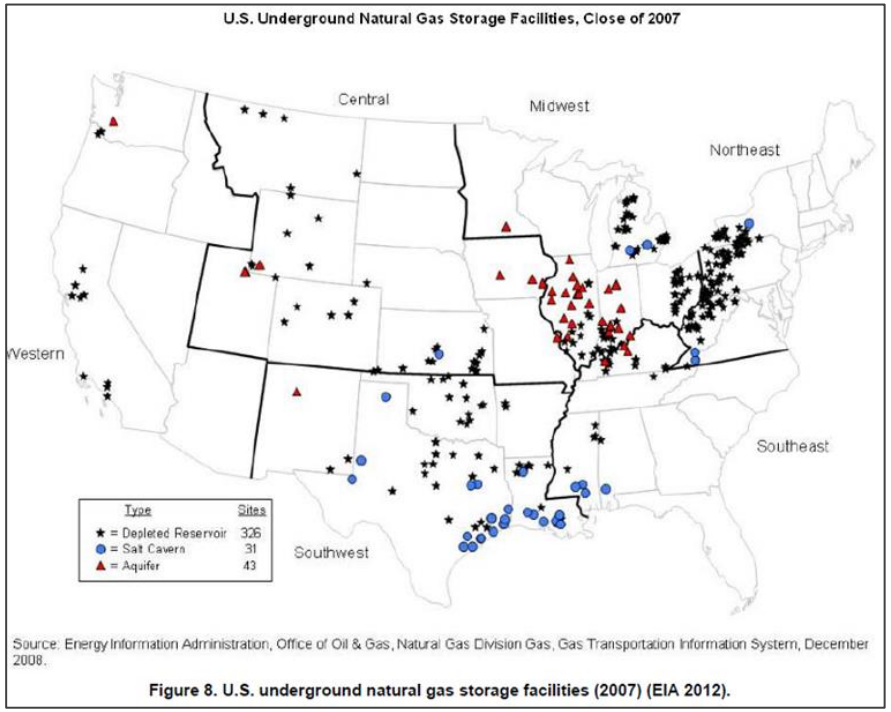


Figure 8. U.S. underground natural gas storage facilities (2007) (EIA 2012).

Source: DOE

Carbon Capture and Storage (CCS) and Direct Air Capture (DAC)

Carbon Capture, Use, and Storage (CCUS)

- One of the carbon mitigation options included in the ICF analysis and modeling is CCUS
- The first step for this potential mitigation option is to capture the CO2 from various possibles sources including:
  - Flue gases of power plants and industrial facilities burning fossil fuels or biomass/biofuel,
  - Process gas streams from industrial facilities (natural gas processing plants, ammonia plants, methanol plants, petroleum refineries, steel mills, cement plants, ethanol plants, etc.)
  - Hydrogen plants using fossil fuels or biomass as feedstocks
  - Air (through the application of direct air capture)
- After capturing CO2, the next steps in CCUS typically are to purify and dehydrate the CO2, compress it for transportation and then either to:
  - Inject it underground into an appropriate geological storage site, where it is trapped and permanently stored in porous rock or
  - Utilize it in one or more of the ways (enhanced oil recovery, chemicals/synfuels, building materials)

Key Features of Modelling Approach for CCUS / Direct Air Capture

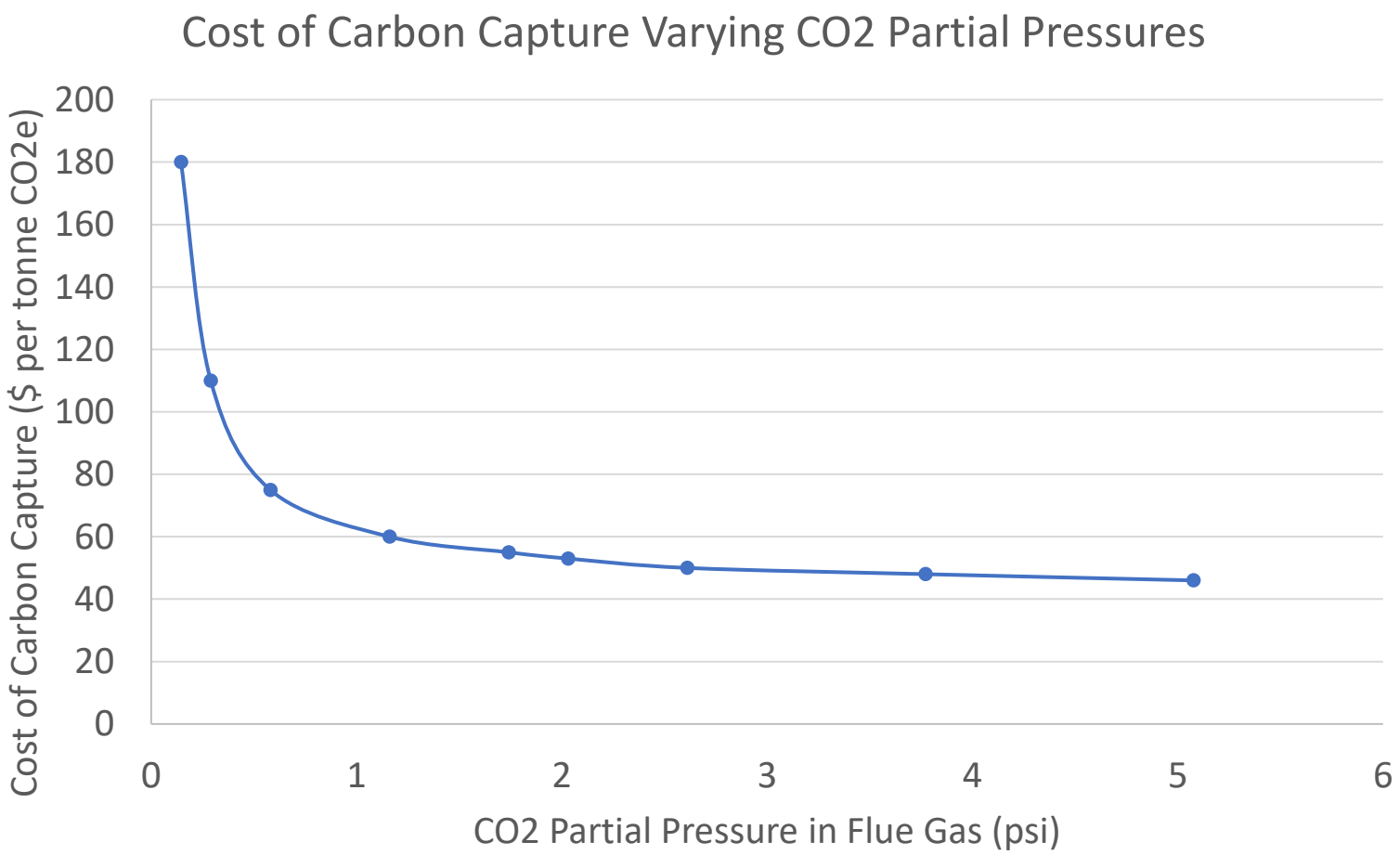
- Capture economics are derived mostly from ICF's standard assumptions which are based on post-combustion capture using amine solvents
- Separate cases were developed for different "submarkets" based size facilities and characteristics of flue/process gas streams (CO2 partial pressure and contaminants)
- Maximum volumes for each submarket were based on customer data provided by each utility or ICF estimates
- Geologic sequestration technologies and economics were based on ICF's "GeoCAT V2.0" model for saline and abandoned oil/gas field sites in or near Oregon and Washington
- Primary source of information on geologic storage capacity are Regional DOE NATCARB studies and the NATCARB Atlas. These provide assessed storage volumes by basin, reservoir type, formation, depth, etc.

Economics of Carbon Capture & Storage / Direct Air Capture

- Both capture and sequestration use "global assumptions" for energy prices and commodity/service price indices (natural gas price, electricity price, well drilling cost, construction cost index, etc.)
- Since they are largely based on mature technologies, the CAPEX and OPEX for flue/process gas capture and storage will be modelled with zero technology improvement factor
- Direct air capture, on the other hand, is immature and is expected to benefit from technological improvements that will bring capture cost from ~ $600/MT now to about $300/MT by 2050. The long-term energy use (capture only) is expected to be
  0.48 MWh/MT of CO_2

Cost of CO_2 capture varies inversely with CO_2 partial pressure. (see figure)

Also affected by several other factors such as facility size, pollutants in flue/process gas, space availability for capture equipment, etc.



Cost of CO2 Capture by Flue Gas Stream

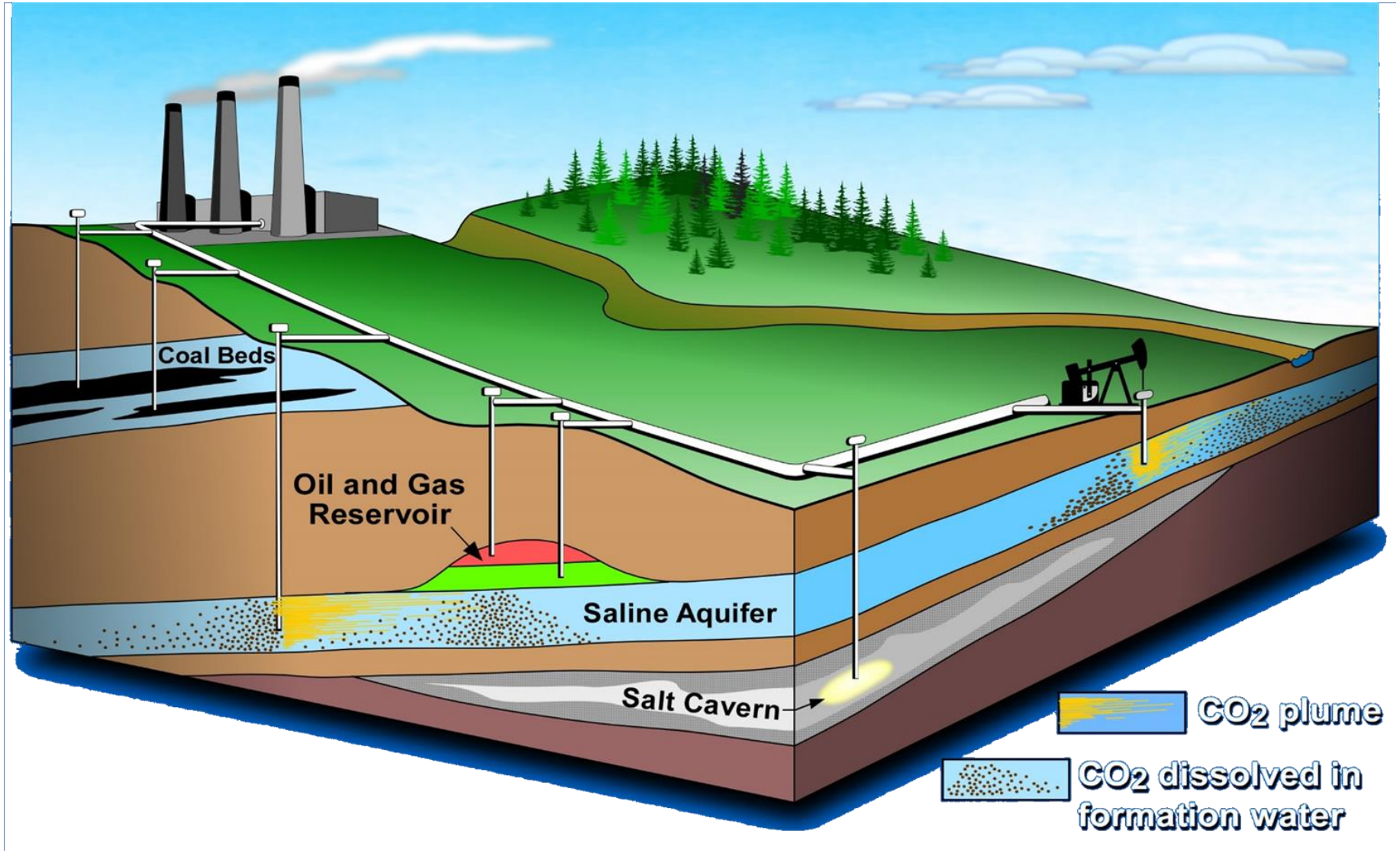
INDUSTRY	POINT SOURCE	CO2 PARTIAL PRESSURE (WET) (PSI)	GAS STREAM PRESSURE (PSI)	INHERENT CO2 CAPTURE	Estimates of Cost of Carbon Capture (2020 USD per tonne CO2)
Power	Natural gas combined cycle (NGCC) power plant	0.55 - 0.67	Atmospheric***	No	$72.12
	Coal fired-power plant	1.77 - 2.06	Atmospheric***	No	$53.00
	Biomass/waste-fired power plant	1.46 - 1.77	Atmospheric***	No	$55.00
Power/Industrial Heat	Natural gas-fired power and/or heat plant (Open Cycle)	0.59 - 1.17	Atmospheric***	No	$60.00
Petroleum Refining/ Petrochemicals	fluid catalytic cracking	1.46 - 2.06	Atmospheric***	No	$52.14
	Process heater	1.17 - 1.46	Atmospheric***	No	$56.10
	Ethylene production steam cracking	1.03 - 1.77	Atmospheric***	No	$53.72
	Steam methane reforming hydrogen production	43.51 - 69.62	290 - 435	No	$42.79
	Ethylene oxide production	>13.34	Atmospheric***	Yes	$43.99
Cement	Kiln flue gas	~2.61	Atmospheric***	No	$50.00
	Pre-calciner	2.9 - 4.35	Atmospheric***	No	$47.07
Pulp and paper	Lime kiln	~2.32	Atmospheric***	No	$51.06
Iron & Steel	COREX smelting reduction process	4.64 - 5.08	Atmospheric***	No	$46.00
	Hot Stove	3.48 - 4.06	Atmospheric***	No	$48.00
	Lime calcining	1.03 - 1.17	Atmospheric***	No	$59.47
	Sinter plant	0.54 - 0.61	Atmospheric***	No	$75.00
Aluminum	Aluminum smelter	0.12 - 0.16	Atmospheric***	No	$180.00
Fertilizer	Coal gasification syngas	108.78 - 362.6	435 - 870	Yes*	$42.56
	Natural gas reforming syngas	43.51 - 174.05	290 - 435	Yes*	$42.62
Natural gas processing	Natural gas processing	Varies up to 725.19	131 - 1189+	Yes, acid gas removal	$43.43
Bioethanol	Ethanol fermentation	>12.33	Atmospheric***		50

*Data based on Global CCS Institute data. Costs are for capture only and exclude dehydration, compression, transportation and storage.

Estimating Potential Capture Volumes

- The analysis of the potential capture volumes was conducted for each of the three utilities based on a list of the largest customers in their respective service territories
- Data provided by the utilities included volume of gas sales and the classification of the customers by industry type. The potential CCUS customers were divided into the eight size classes shown below. The industry classification was used to develop approximate values for the average partial pressures (an important parameter in the cost estimation) for each grouping
  - under 25 MMBtu/hour
  - 25-50 MMBtu/hour
  - 50-100 MMBtu/hour
  - 100-200 MMBtu/hour
  - 200-400 MMBtu/hour
  - 400-800 MMBtu/hour
  - 800-1600 MMBtu/hour
  - 1600+ MMBtu/hour
- The potential volumes that could be captured are computed assuming a 90% capture rate
- It is assumed that the facilities in the utility company customer databases (or other facilities with similar characteristics) will continue to operate throughout the forecast period to 2050

Means of CO_2 Geological Storage

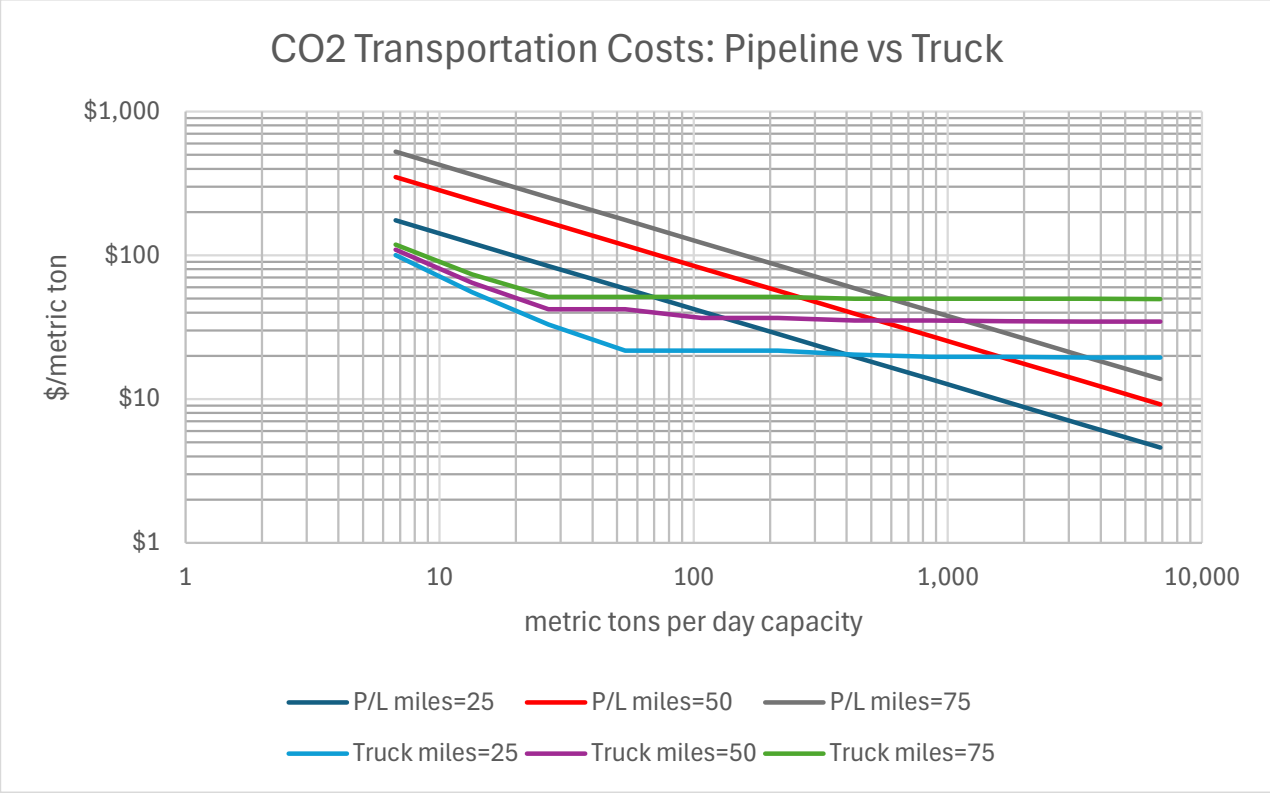


Geologic Storage Costs

- Geologic storage costs are computed in terms of levelized dollars per metric ton of stored CO2
- These costs is largely a function of the geologic characteristics of each project and assumptions used in the costing algorithms for individual construction and operating components of geologic sequestration of CO2
- The largest economic drivers are the costs of well operation, injection and monitoring well construction costs, and the costs of site monitoring
- Depending on the nature of each cost element, “unit costs” are specified as dollars per storage site, dollars per square mile, dollars per foot as a function of well depth, dollars per labor hour, or other kinds of specifications or algorithms. The unit cost specification module includes data and assumptions for about 105 cost elements falling within the following ten general cost categories:
  - Geologic Site Characterization
  - Area of Review (AoR) Study & Corrective Action
  - Injection Well Construction
  - Operation of Injection Wells & Pumps
  - Water Management Capex & Opex
  - Monitoring & Reporting Capex and Opex, includes mechanical integrity tests (MIT)
  - Financial Responsibility
  - Post-Injection Site Care & Site Closure
  - General & Administrative Costs
- The weighted average geologic storage cost for saline aquifers in the Lower 48 is $16.70/MT computed on a levelized basis

CO2 Transportation

- ICF's costs of pipeline transportation are based on standard engineering calculations for what diameter of pipeline is needed to transport a given volume of CO2
- The capital cost of the CO2 pipelines is represented in the ICF cost model in terms of dollars per inch-mile
- Small volumes of CO2 are assumed to be transported by truck



Use of Stochastic Variables for the CCUS Cost Analysis

- There were no stochastic variables created specifically for carbon capture, use and storage (CCUS)
- However, the cost analysis for CCUS employed several of the global stochastic variables also used in the other techno-economic models. These variables include:
  - The price of crude oil and diesel fuel (these affected the cost of drilling CO2 storage wells and the cost of truck transportation of CO2)
  - Natural gas prices (these affected the cost of the amine capture process).
  - Industrial electricity prices (these impacted the costs for capture, dehydration and compression, and pipeline transportation of CO2)
  - Various indices such as those for well drilling cost, industrial facility construction, cost of capital, etc.

CCUS Cost for Base Case Assumptions (2030)

CCUS Cost Results for Base Case Assumptions for Year: 2030													
Resource Subcategory or Step	Distance to Storage Site (miles)	Storage Type	CO2 Partial Pressure (psi)	Fraction CO2 Captured	Annual Capacity Utilization Rate	Capital Costs ($million)	Annual O&M + Energy Costs ($million)	Total Cost ($/MT of CO2 captured)	Dehydration & Compression ($/MT)	Trans Mode	Transport ($/MT)	Storage ($/MT)	Sum All CCS Costs ($/MT, before 45Q tax credit))
under 25MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**81.2%**	$2.49	$0.63	$117.97	$19.75	Truck	$64.55	$10.00	$212.26
25-50MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**62.7%**	$3.08	$0.67	$128.55	$21.72	Truck	$42.16	$10.00	$202.44
50-100MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**43.9%**	$3.66	$0.67	$155.75	$26.16	Truck	$42.16	$10.00	$234.07
100-200MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**53.6%**	$8.34	$1.40	$97.73	$20.27	Truck	$42.16	$10.00	$170.16
200-400MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**70.1%**	$14.31	$2.77	$72.19	$16.93	Truck	$36.57	$10.00	$135.69
400-800MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**85.0%**	$37.88	$9.33	$55.90	$15.12	Pipeline	$22.89	$10.00	$103.91
800-1600MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**75.0%**	$59.67	$14.41	$55.72	$15.93	Pipeline	$16.99	$10.00	$98.64
1600+MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**75.0%**	$103.90	$27.69	$52.34	$15.88	Pipeline	$11.80	$10.00	$90.03
Direct Air Capture	50	Geologic, Acquifer, Medium Injectivity			**85.0%**	$1,836.76	$116.97	$593.23		Pipeline	$16.07	$10.00	$619.30

Costs represent all segments of supply-chain and are in 2022 dollars.

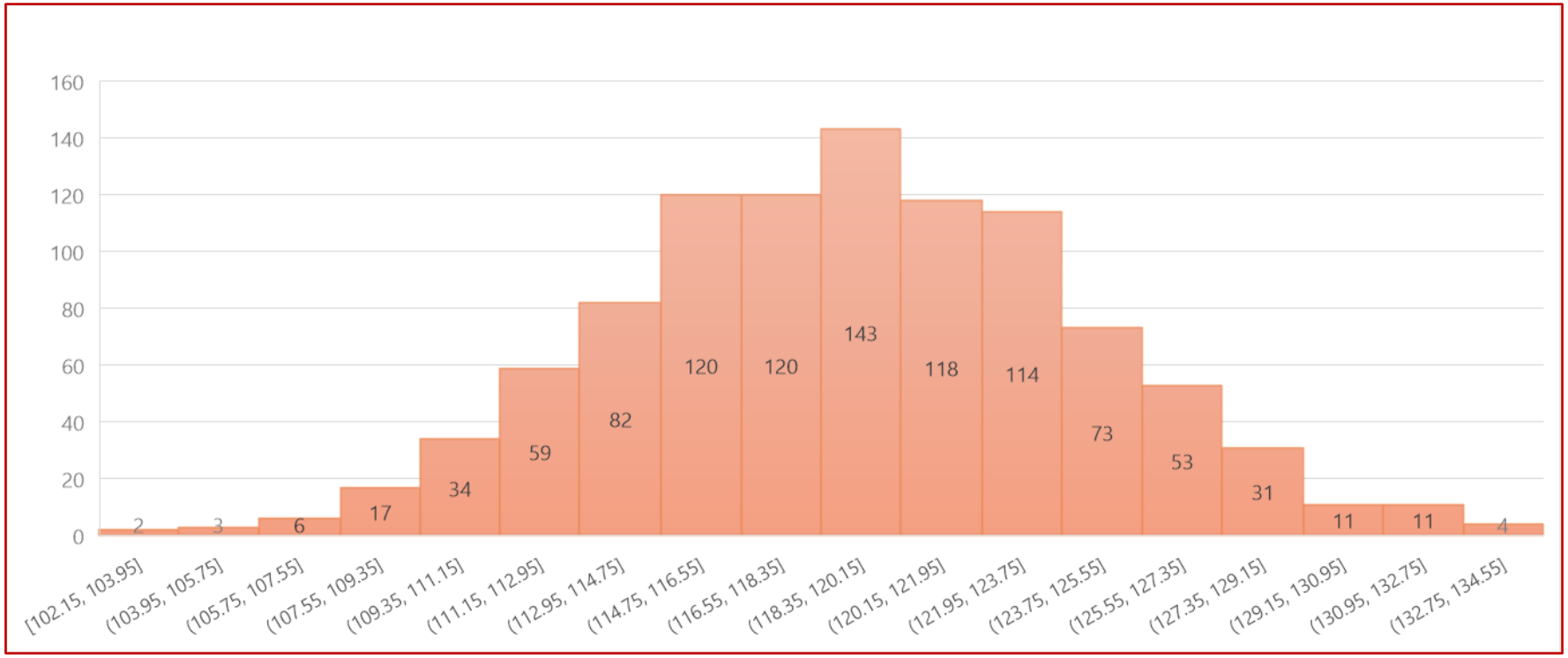
CCUS Cost for Base Case Assumptions (2050)

CCUS Cost Results for Base Case Assumptions for Year: 2050													
Resource Subcategory or Step	Distance to Storage Site (miles)	Storage Type	CO2 Partial Pressure (psi)	Fraction CO2 Captured	Annual Capacity Utilization Rate	Capital Costs ($million)	Annual O&M + Energy Costs ($million)	Total Cost ($/MT of CO2 captured)	Dehydration & Compression ($/MT)	Trans Mode	Transport ($/MT)	Storage ($/MT)	Sum All CCS Costs ($/MT, before 45Q tax credit))
under 25MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**81.2%**	$2.73	$0.67	$125.29	$23.31	Truck	$64.55	$10.00	$223.15
25-50MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**62.7%**	$3.37	$0.70	$136.88	$25.96	Truck	$42.16	$10.00	$215.01
50-100MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**43.9%**	$4.00	$0.71	$166.08	$31.66	Truck	$42.16	$10.00	$249.91
100-200MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**53.6%**	$9.12	$1.50	$105.59	$25.01	Truck	$42.16	$10.00	$182.77
200-400MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**70.1%**	$15.65	$3.00	$78.41	$20.86	Truck	$36.57	$10.00	$145.84
400-800MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**85.0%**	$41.44	$10.16	$60.95	$18.58	Pipeline	$27.70	$10.00	$117.23
800-1600MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**75.0%**	$65.27	$15.72	$60.80	$19.68	Pipeline	$20.52	$10.00	$111.01
1600+MMBtu/hr	50	Geologic, Acquifer, Medium Injectivity	0.882	**90.0%**	**75.0%**	$113.64	$30.21	$57.14	$19.64	Pipeline	$14.24	$10.00	$101.01
Direct Air Capture	50	Geologic, Acquifer, Medium Injectivity			**85.0%**	$1,360.71	$93.19	$454.87		Pipeline	$19.41	$10.00	$484.28

Costs represent all segments of supply-chain and are in 2022 dollars.

Histogram on CCUS Costs Size 400-800MMBtu/hr for 2050

- This histogram depicts the number of the 1,000 Monte Carlo cases (y-axis) that fall within various cost ranges (x-axis) for capture and geologic storage of facilities in the 400-800 MMBtu/hr. size class
- This distribution of cost has a mean of $119.10/MT of CO2 and a standard deviation of $5.19/MT of CO2



Synthetic methane

Synthetic methane

Synthetic methane production considered via two pathways

(1) Thermal gasification of biomass

Referred to as *synthetic methane (biomass)* throughout

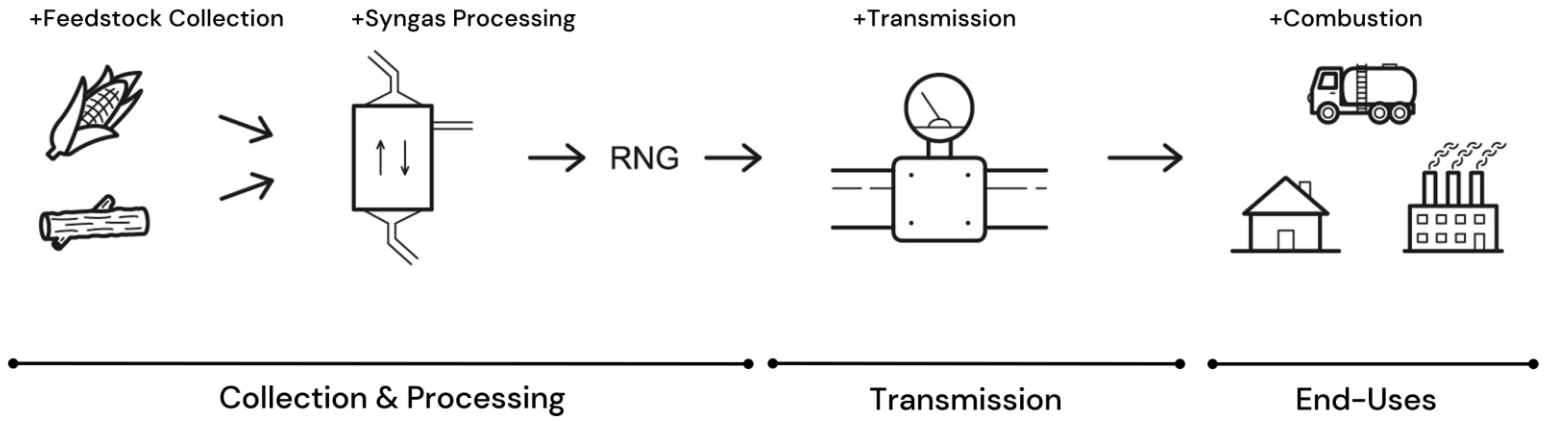
(2) Methanation of electrolytic hydrogen (power-to-gas)

Referred to as *synthetic methane (hydrogen)* throughout

Note: both pathways can also be considered renewable natural gas

Synthetic methane (biomass) production via gasification

- Synthetic methane via thermal gasification has multiple steps
- Biomass is delivered to a gasifier / reactor and heated to high temperatures, and in the presence of a catalyst, an oxidizing agent helps break down the organic molecules into syngas (H_2 + CO)
- In this case, syngas is then methanated to produce CH_4 (RNG in the figure)



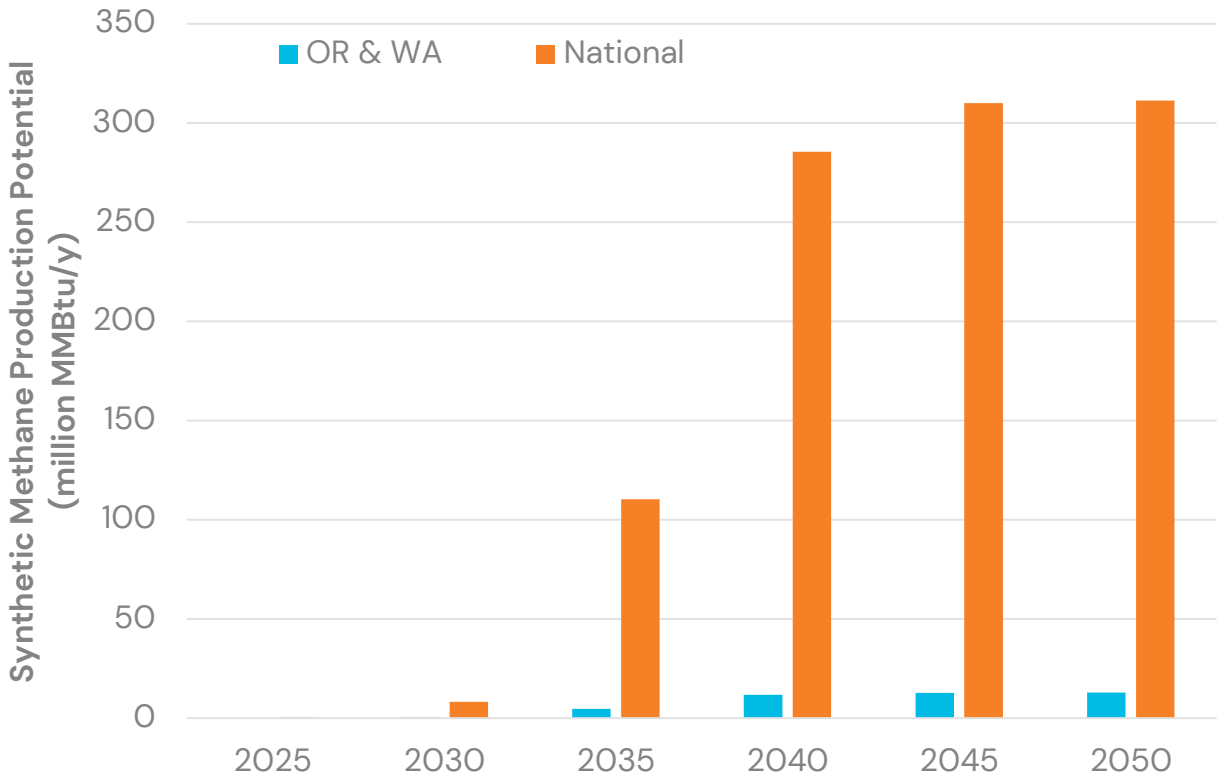
Synthetic Methane (Biomass)– Feedstocks and Data Sources

- Data sources vary by feedstock:
  - Other feedstocks have county-level estimates for biomass.
- U.S. DOE Billion Ton Report leveraged updated datasets, additional feedstock categories (not all relevant to RNG), and introduced market scenarios for its latest characterization of U.S. biomass resources.

Feedstock	Description
Agricultural residue	The material left in the field, orchard, vineyard, or other agricultural setting after a crop has been harvested. Inclusive of unusable portion of crop, stalks, stems, leaves, branches, and seed pods.
Forest and forestry residue	Biomass generated from logging, forest and fire management activities, and milling. Inclusive of logging residues, forest thinnings, and mill residues. Also materials from public forestlands, but not specially designated forests (e.g., roadless areas, national parks, wilderness areas).
Energy crops	Inclusive of perennial grasses, trees, and some annual crops that can be grown specifically to supply large volumes of uniform, consistent quality feedstocks for energy production.
MSW	Refers to the biogenic fraction of waste that would be landfilled, excluding construction and demolition debris, plastics, etc.

Synthetic Methane (Biomass) Resource Potential

- Derived estimates from an ICF study for American Gas Foundation (AGF 2019). Used the High Resource Potential case from that study
- OR/WA estimates are based on in-state production potential
- National estimate is the population-weighted *share* of the national pool of RNG resource to which NW utilities are expected to have access
- Assumed that these feedstocks are used in thermal gasification pathways to produce RNG.



Cost elements for gasification

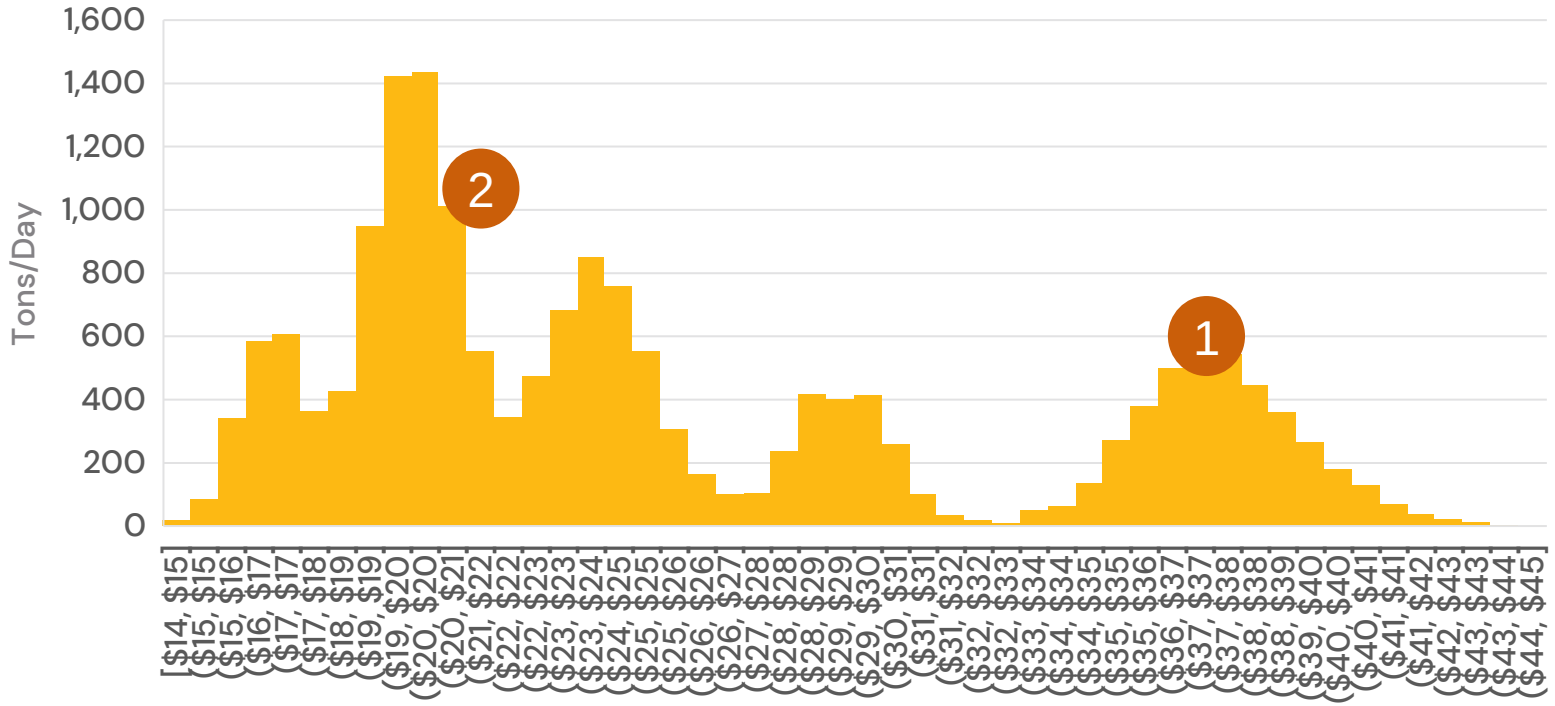
- There are small scale facilities operational processing biomass today
- Feasibility relies on transition to larger facilities handling larger amounts of biomass e.g., 2,000 tons per day (tpd)
- Engineering cost estimates—less project data than anaerobic digestion

Cost element	Facility 1	Facility 2	Facility 3
Facility sizing | biomass, tpd	200	1,000	2,000
CH4 production (million MMBtu/y)	0.44	2.4	5.2
Capacity factor	90-95%		
Installation costs	$41.5	$120.9	$191.9
CapEx	$131.30	$382.80	$607.50
Pipeline & Interconnect	$5.0		
O&M, equipment	10-20%		
O&M, electricity, kWh/MMBtu	45	40	38
O&M, natural gas, MMBtu/MMBtu	25%	25%	25%
Financial parameters	20-year term | 4% WACC		

LCOG results for synthetic methane (biomass), 2030

1. Initial facilities likely in this range (or more expensive)

2. Larger projects process 1,000-2,000 tons per day (tpd) show attractive production economics



Synthetic methane (biomass) cost projection, MC Results

- Range reflects project scale and associated assumptions re: improved economics
- Feedstock costs are uncertain, but Monte Carlo cases reflect this range ($37-90/dry ton)

Oregon and Washington

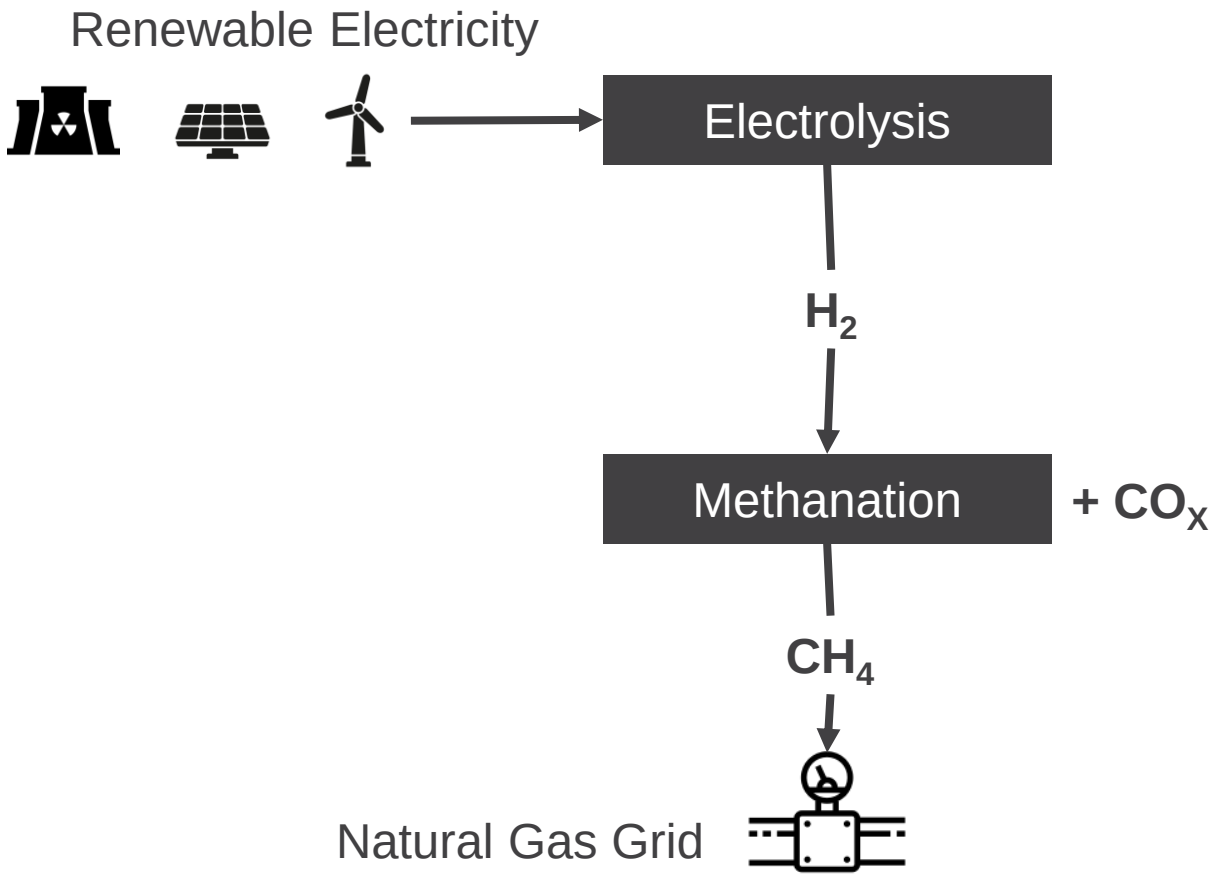
RNG Feedstock	2030	2050
Biomass	$16-$44	$19-$57

National ($/MMBtu)

RNG Feedstock	2030	2050
Biomass	$14-$32	$17-$45

Synthetic methane (H2) production

- Synthetic methane from hydrogen is produced by the methanation of renewable hydrogen (produced from electrolysis) in the presence of CO_2
- CO_2 source can vary
  - Assumed biogenic, CCS, DAC (see slides 59-71)
- Analysis draws from hydrogen work, with electrolysis powered by wind, solar, and nuclear (see slides 51-57)



Synthetic methane (H2) Resource Potential

- Resource is limited by hydrogen; and hydrogen production is limited by renewable deployment and global electrolyzer capacity (GW)
- OR / WA estimates were developed on a population-weighted basis after adjusting for decarbonization policies in different states

Cost elements for methanation

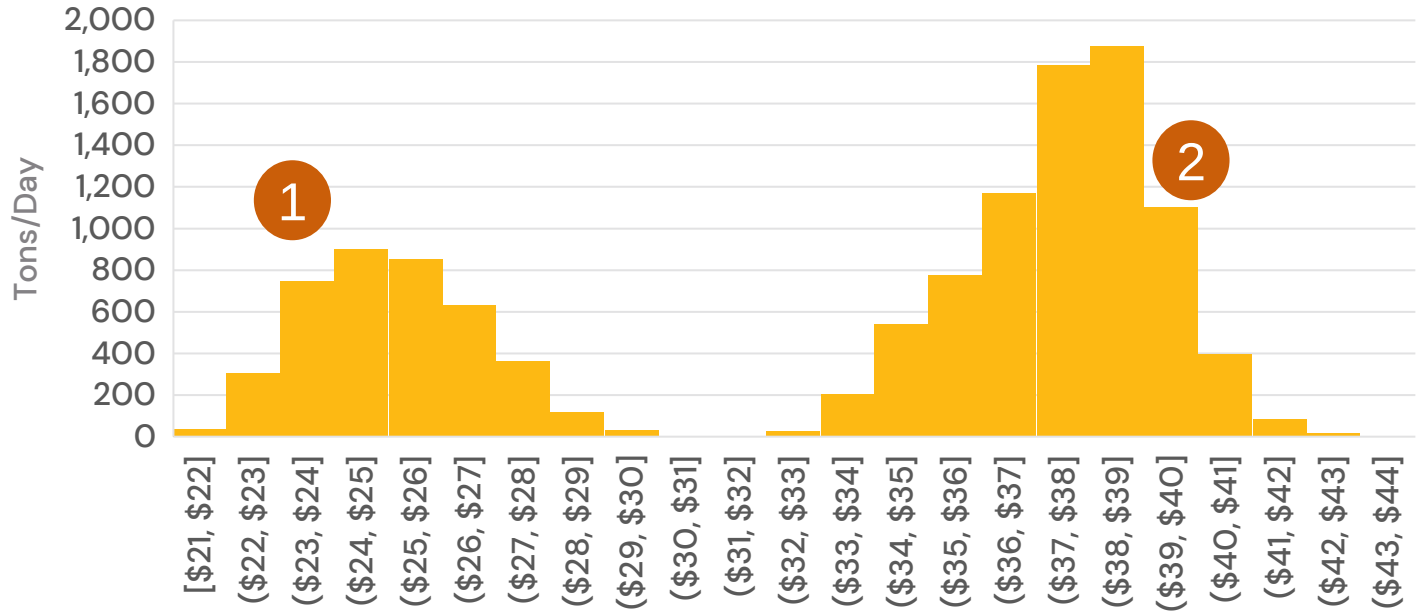
- Methanation is industrial technology
- Limiting factors will be H_2 (cost + resource) and CO_2 (cost + resource)

Cost element	Methanation of electrolytic hydrogen		
Electrolyzer (MW)	220		
CH4 production (million MMBtu/y)	3.8		
Capacity factor	90-95%		
CapEx	$45.3		
Pipeline & Interconnect	$5.0		
O&M, equipment	10-20%		
Hydrogen	See other slides		
CO2	Biogenic	CCS	DAC
Financial parameters	20-year term | 4% WACC		

LCOG results for synthetic methane (H2), 2030

1. Lower costs observed up to 2030 b/c of hydrogen PTC

2. Higher cost nuclear power drives higher LCOG



Synthetic methane (H2) cost projection, MC Results

- Range reflects MC variation for H2, CO2 source cost differential, and methanation step
- Costs rise post-2030 with expiration of 45V

Oregon and Washington

Electricity source	2030	2050
Wind	$34-$46	$55-84
Solar	$29-$40	$44-61
Nuclear	$35-$42	$59-$77

National ($/MMBtu)

Electricity source	2030	2050
Wind	$31-$43	$54-$81
Solar	$21-$30	$45-63
Nuclear	$35-$43	$58-$77

Get in touch with us:

Andrew Griffith
Manager
Andrew.Griffith@ICF.com

linkedin.com/company/icf-international/

twitter.com/icf

https://www.facebook.com/ThisIsICF/

icf.com

About ICF

ICF (NASDAQ:ICFI) is a global consulting and digital services company with over 7,000 full- and part-time employees, but we are not your typical consultants. At ICF, business analysts and policy specialists work together with digital strategists, data scientists and creatives. We combine unmatched industry expertise with cutting-edge engagement capabilities to help organizations solve their most complex challenges. Since 1969, public and private sector clients have worked with ICF to navigate change and shape the future.

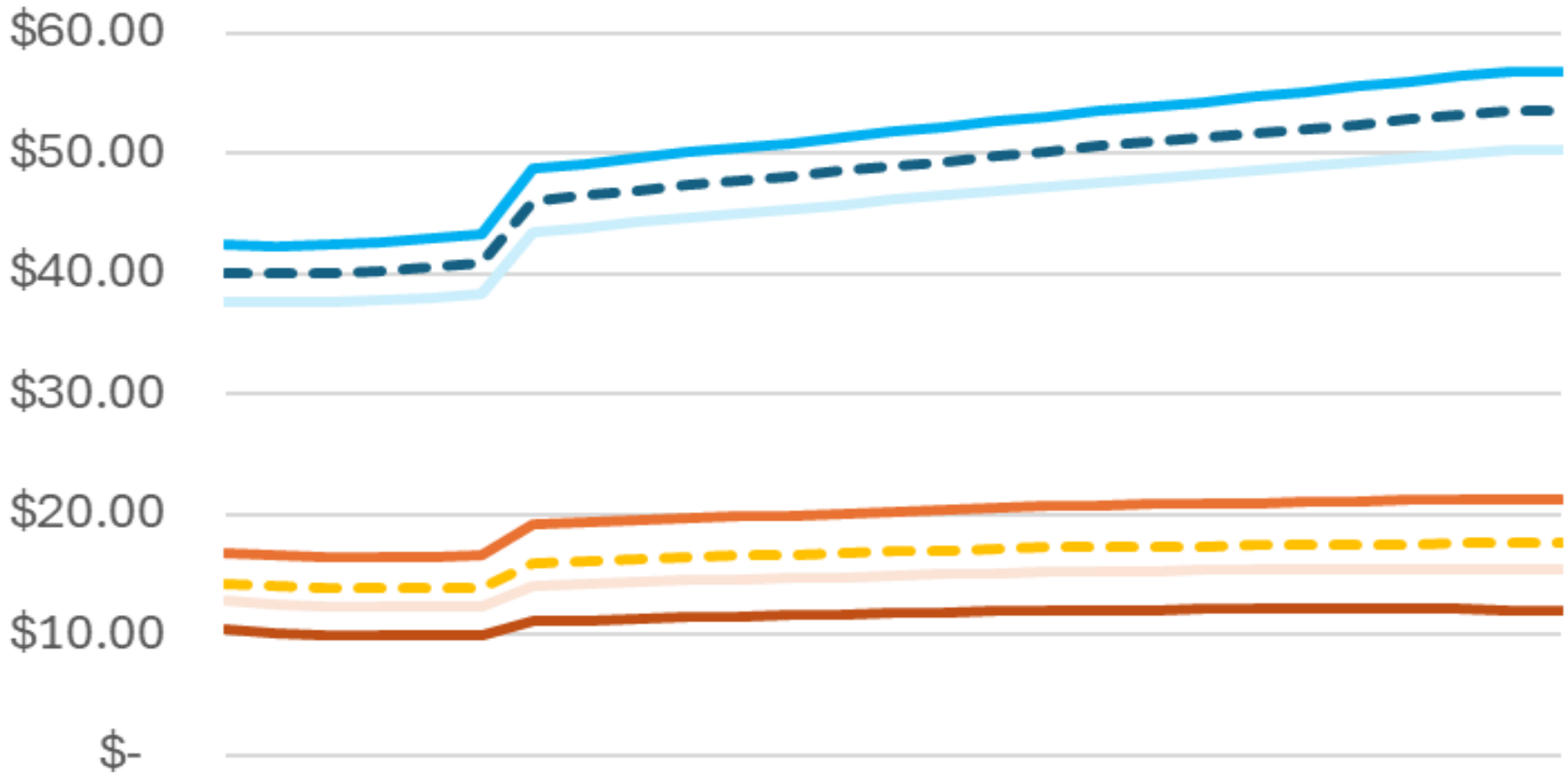
Resource Optimization Modeling

Alternative Fuels and Carbon Capture for IRP Analysis

- For IRP Modeling through the Resource Optimization Planning Model, we need to bucket resources to a reasonable number of proxy resources for evaluation
- We are aiming to modeling 23 separate buckets of compliance resources
  - Still running into computational constraints and may need to drop high-cost options that we intuitively know are unlikely to be selected in the PLEXOS model
- Summing quantities that would be available to NW Natural
  - 33% of Pacific Northwest Numbers and downscaled National Numbers
- Pricing is based on weighted averages across more granular types/project sizes provided by ICF models

Category	Type	Costs Differentiation	
Near Term RTC Opportunities	Short Term Contracts	Low Cost	1
		High Cost	2
	Long Term Contracts	Low Cost	3
		High Cost	4
Long Term RTC Opportunities	RTC Purchases	Base Cost	5
Renewable Natural Gas	Land Fill Gas	Low Cost	6
		High Cost	7
	Animal Manure	Low Cost	8
		High Cost	9
	Wastewater	Low Cost	10
		High Cost	11
	Food Waste	Low Cost	12
		High Cost	13
Hydrogen	Green from Dedicated Solar	Base Cost	14
	Green from Dedicated Wind	Base Cost	15
	Blue Hydrogen	Base Cost	16
	Turquoise Hydrogen	Base Cost	17
Synthetic Methane	Biomass	Low Cost	18
		High Cost	19
	Green from Dedicated Solar	Base Cost	20
	Green from Dedicated Wind	Base Cost	21
Carbon Capture Utilization and Storage	Industrial Customers	Base Cost	22
	Direct Air Capture	Base Cost	23

Example: Wastewater RNG Gas (Bundled Product)

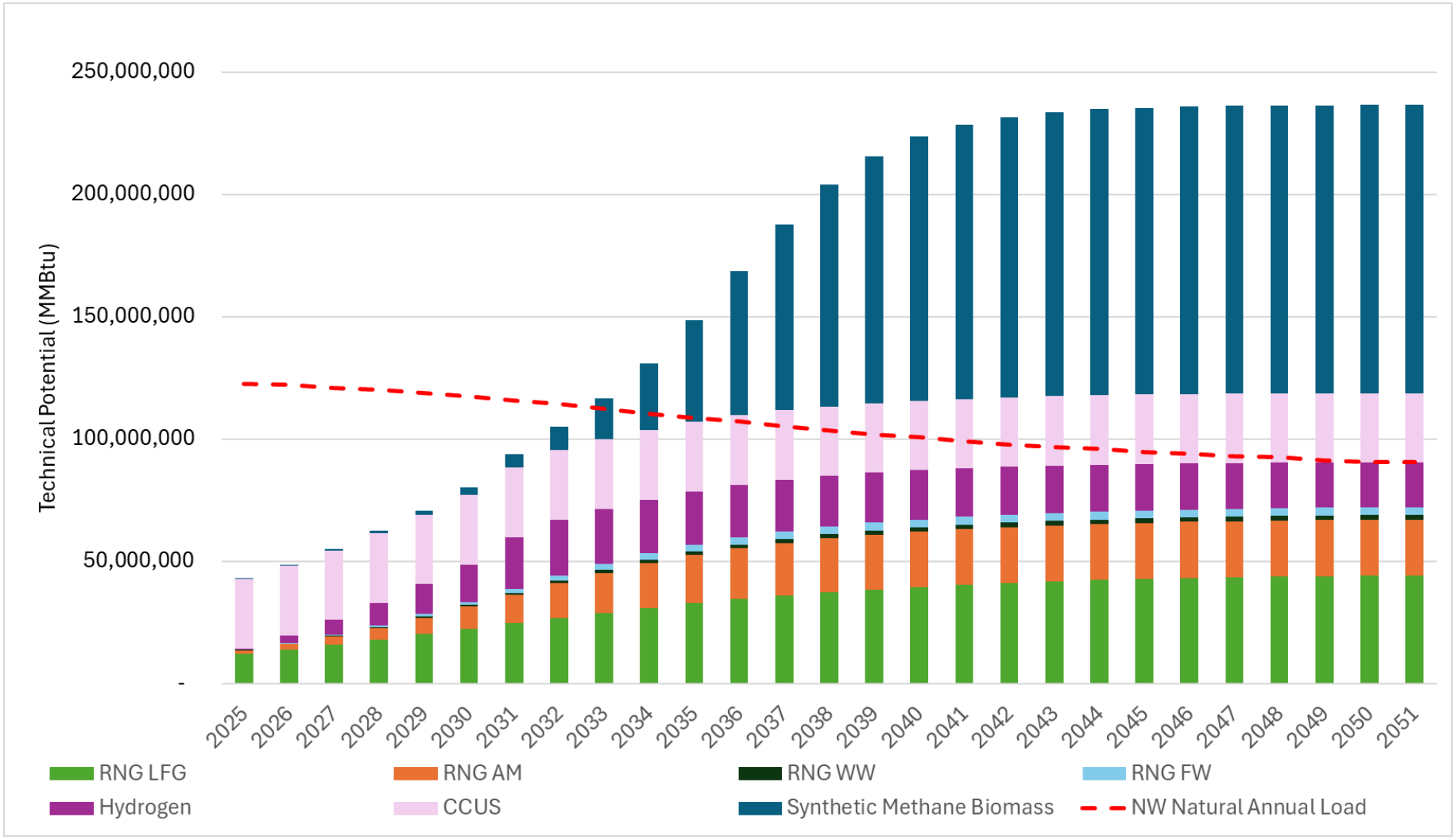


- Prices for alternative fuels are for a bundled product (i.e., environmental attributes plus commodity)
- A forecasted Henry Hub price is subtracted out to get an equivalent unbundled price for comparison with other unbundled compliance instruments

⇨ From ICF's Models

⇨ Weighted Average for PLEXOS

Alternative Fuel and CCUS Quantities



- Quantities have been downscaled to what could be available to NW Natural
- Hydrogen is capped at 20% of load by energy
- This accounts for both blending some hydrogen into the system and industrial customers using 100% hydrogen
- Synthetic methane from Green Hydrogen is excluded from this graph but will be included in our resource modeling

Feedback Form

Feedback preferred by February 11th

https://www.surveymonkey.com/r/NWNaturalIRP

Thank you!

We value your feedback.

IRP@nwnatural.com

IRP Website

IRP Feedback Form